Power Advisory LLC

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November 16, 2018

Dear Barbara,

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 comments on the Independent Electricity System Operator's (IESO's) draft Single Schedule Market (SSM) High-Level Design (HLD)[2] that was released on September 27, 2018. Essentially, this submission comments on the draft SSM HLD plan to move to a wholesale energy pricing regime of Locational Marginal Prices (LMPs)[3] in Ontario and related implications to other areas within the IESO's Market Renewal Program (MRP) and outside of the IESO-Administered Markets (IAM).

Overview of Main Comments and Recommendations

The main comments and recommendations within this submission are listed below.

- Overall, the draft SSM HLD is a good document providing clear high-level direction to implement an LMP pricing regime within the IAM.
- The planned move to an LMP pricing regime must address: (i) specific pricing and operational issues within the IAM (e.g., negative prices in the northern zones); and, (ii) applicable contract amendments in accordance with forthcoming amendments to the IESO Market Rules.
- The Consortium recommends that a sixth area to address contract amendments be added to the forthcoming MRP Energy Workstream detailed design stakeholder consultations.
- Principles for price fidelity within the IAM should be established to help guide detailed design decisions, rules, and protocols to be determined within the Energy Workstream detailed design consultations towards ensuring that market clearing prices accurately and effectively reflect

[1] The members of the Consortium are: Algonquin Power; Axium Infrastructure; BluEarth Renewables; Boralex; Brookfield Renewable Power; Canadian Wind Energy Association; Capstone Infrastructure; Cordelio Power; EDF Renewables; EDP Renewables; Enbridge; Energy Storage Canada; ENGIE; H2O Power; Innergex; Kruger Energy; NextEra Energy Canada; Pattern Energy; Suncor; wpd Canada; and, Canadian Solar Industries Association.

[2] See http://www.ieso.ca/Sector-Participants/Market-Renewal/Single-Schedule-Market-High-Level-Design

[3] Specifically, LMPs are being planned for energy and operating reserve (OR). The remaining sections of this submission refer to LMPs for energy but implicitly means to also capture LMPs for OR where appropriate.

supply/demand conditions including scarcity. For example, the IESO should explore design of an operating reserve (OR) Demand Curve during the Energy Workstream detailed design consultations.

- Negative market clearing prices in the northwest zone requires priority attention within the Energy Workstream detailed design consultations.
- Make-whole payments should also be prioritized within the Energy Workstream detailed design consultations, which is further needed in consideration of potential negative pricing issues.
- Market power mitigation design, rules, and protocols must be transparent and offer sufficient recourse, in the event Market Participants (MPs) disagree with the IESO's application of market power mitigation.
- Load pricing and potential causal changes to rate design and allocation of charges (e.g., Global Adjustment (GA)) will impact energy consumption decisions for all load customers, which will have implications for the application and deployment of resources (e.g., energy storage) that could be used to help manage electricity customers' energy consumption and meet power system needs.
- The IESO should develop a Roadmap/Workplan to evolve the IAM beyond the MRP design components and plans within the present Energy and Capacity Workstreams. This Roadmap/Workplan should include design components relating to valuing environmental attributes and potential for new electricity products (e.g., ramping, etc.).

About the Consortium and Organization of this Submission

The Consortium members (aside from the associations) own and operate approximately 5,550 MW of generation and energy storage facilities in Ontario[4], with the majority of these facilities registered as MPs transacting within the IAM. Familiarity with operating within the IAM, combined with operations within other North American[5] and global wholesale electricity markets with LMP pricing regimes places the Consortium in an experienced and helpful position to comment on the draft SSM HLD.

The Consortium's wind, hydroelectric, and solar generation facilities are mostly operating as dispatchable resources within the IAM, some as self-scheduling generators, representing the majority of renewable generation contract types[6]. Therefore, the Consortium members have extensive experience regarding considerations and impacts of IAM operations and revenues relating to contract obligations and revenues.

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[4] See Appendix A for a list of Consortium member generation and energy storage facilities operating or being developed in Ontario

[5] Independent System Operator New England (ISO-NE), New York ISO (NYISO), Pennsylvania-New Jersey-Maryland Interconnection (PJM), Midcontinent ISO (MISO), Southwest Power Pool (SPP), California ISO (CAISO), Electricity Reliability Council of Texas (ERCOT), Alberta Electricity System Operator (AESO)

[6] Contract types include, but not limited to, Renewable Energy Supply (RES) (i.e., RES I, RES II, and RES III), Feed-in Tariff (FIT), Large Renewable Procurement I (LRP I), and Hydroelectric Contract Initiative (HCI).

The remaining sections within this submission provide: (i) general comments regarding the draft SSM HLD related to the IAM and beyond; (ii) specific comments relating to operating facilities within the IAM and projects being developed by Consortium members within Ontario; (iii) detailed comments regarding the draft SSM HLD itself; and, (iv) concluding comments.

General Comments on Draft SSM HLD – IAM and Beyond IAM

Impacts of Implementing LMPs Must be Addressed to Achieve Benefits of SSM and MRP

The Consortium understands why the IESO has been working with stakeholders since early 2017 to plan a move away from the SSM pricing regime of wholesale uniform energy prices[7] and Congestion Management Settlement Credits (CMSC)[8] towards implementation of LMPs. The planned move to an LMP pricing regime must also address: (i) specific pricing and operational issues within the IAM (e.g., negative LMPs in northern zones); and, (ii) applicable contract amendments in accordance with forthcoming amendments to the IESO Market Rules[9].

Contract Amendments Not Addressed in Draft SSM HLD and Need to Be Specifically Addressed within MRP Energy Workstream Detailed Design Consultations

As first discussed within the Market Renewal Working Group (MRWG)[10], the Consortium supports plans to consult with stakeholders within the detailed design areas covering SSM, Day-Ahead Market (DAM), and Enhanced Real-Time Unit Commitment (ERUC) together: (i) Forecasting and Modelling; (ii) Price Formation; (iii) Market Power Mitigation; (iv) Market Participation, Scheduling and Dispatch; and, (v) Settlements.

However, due to the integrated nature of contracts, the Consortium recommends that a sixth topic area addressing contract amendments be established to best ensure timely and effective coordination with planned market design changes and amendments to the IESO Market Rules relating to the Energy

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[7] Elimination of the Hourly Ontario Energy Price (HOEP) and the five-minute Market Clearing Price (MCP), where of the other North American wholesale electricity markets only AESO still administers uniform wholesale energy prices. That is, ISO-NE, NYISO, PJM, MISO, SPP, CAISO, and ERCOT all administer LMP pricing regimes.

[8] The Consortium acknowledges many issues have persisted since the May 2002 opening of the IAM relating to the SSM design of uniform prices combined with CMSC, as documented within several Ontario Energy Board (OEB) Market Surveillance Panel (MSP) reports (see https://www.oeb.ca/utility-performance-and-monitoring/electricity-market-surveillance/panel-reports).

[9] In addition to LMP related amendments to the IESO Market Rules, also includes other wholesale energy market related amendments to the IESO Market Rules planned within the IESO's MRP (e.g., implementation of DAM and ERUC)

[10] See MRWG September 24, 2018 presentation available at http://www.ieso.ca/Sector-Participants/Market-Renewal/Market-Renewal-Working-Group

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Workstream's SSM, DAM, and ERUC components. This recommendation is important considering that the draft SSM HLD did not address contract amendments.

Importance of Wholesale Energy Price Fidelity and Inputs to Formation of LMPs

To date the SSM stakeholder consultation has focused on the main components of calculating LMPs (i.e., reference price determination, congestion calculations, calculation of transmission losses, etc.). The draft SSM HLD does not address price fidelity[11] or other inputs regarding the formation of LMPs. The Consortium acknowledges that these two areas will likely be addressed during the Energy Workstream detailed design consultations (i.e., perhaps within the Price Formation detailed design area). However, because of their omission within the draft SSM HLD, these two aspects of price formation are discussed in more detail below.

Price Fidelity – Importance of Price Signals and Valuing Demand/Supply Scarcity

While implementation of LMPs will more accurately value locational energy demand/supply compared to uniform HOEPs and MCPs, LMPs should be effective price signals that most accurately reflect locational energy demand/supply balance, and not be artificially distorted, muted, or suppressed by other areas of market design, rules, and/or protocols. For example, the following areas can work to distort, mute, and/or suppress LMPs if not carefully designed and implemented:

- Maximum and minimum market clearing price caps and floors;
- Components of offers and bids;
- Offer and bid price caps;
- Offer and bid price floors;
- Value of constraint violations and relaxation of constraint violations;
- IESO control room operator 'out-of-market' actions;
- Resources (e.g., generators, loads, importers, exporters, etc.) eligible to set market clearing prices;
- Calculation of market clearing prices based on other scheduling/dispatch optimization inputs (e.g., ramp rates, etc.);
- Application of market power mitigation (e.g., determination of thresholds and reference levels within ex-ante market power mitigation, etc.); and
- Use of peak demand forecasts versus average demand forecasts or actual demand.

The IESO should specifically engage in consultation with MPs, electricity customers, and other key stakeholders to develop principles and objectives for price fidelity within the IAM. The result of developing principles and objectives should then provide guidance to determining how LMPs will be calculated, trade-offs across applicable areas of market design, rules, and protocols that can impact LMPs,

[11] Price fidelity is a term sometimes used within wholesale electricity markets which describes the accuracy and exactness of prices

and ultimately how accurate LMPs will be in reflecting actual energy demand/supply balance including scarcity.

In previous years, the IESO worked with stakeholders on issues with a history of impacting market clearing prices within the IAM. The IESO's former Market Pricing Working Group (MPWG) identified many issues[12] that should be addressed within the Energy Workstream detailed design consultations, and are consistent with the areas listed above regarding how LMPs could be distorted, muted, and/or suppressed if price formation is not carefully designed and implemented. Therefore, the Consortium recommends that the IESO review the MPWG issues list to help inform market design, rules, and protocols that will need to be addressed in the detailed design phase.

Considering the IESO's plans to lessen the use of procurement contracts[13] combined with planned implementation of Incremental Capacity Auctions (ICAs), calculation of LMPs yielding wholesale energy market revenues will be extremely important for operations and maintenance of existing resources and development of new resources. Capacity prices and revenues are being planned to be set 'net' of wholesale energy market and ancillary services prices and revenues[14]. Therefore, LMPs will impact ICAs. Also, the variable nature of wind and solar means these generators will not have the same capacity value as other generators. As a consequence, variable generators will receive less capacity revenues and will rely proportionately more on wholesale energy market revenues to ensure cost recovery and rate of return on investments. The IAM must retain as much value as possible in the wholesale energy market to accurately reflect demand/supply and ensure that market clearing prices are not distorted, muted, and/or suppressed.

<u>Other Inputs to Formulate LMPs</u>

While the Consortium acknowledges that technical aspects of LMPs are more appropriately left for the Energy Workstream detailed design consultations, it is important to note that other factors and inputs can influence how LMPs are set. This is consistent with the Consortium's recommendation that principles and objectives for price fidelity within the IAM be established to best ensure that market clearing prices accurately reflect demand/supply balance and scarcity. Examples of other factors that will determine how

[12] See Appendix B for a MPWG issues list

[13] The IESO has indicated that, although currently the province meets its capacity needs through a combination of regulated and contracted resources, it will move towards implementing an enduring market-based mechanism that will secure capacity to help ensure Ontario's reliability needs are met cost effectively. See http://www.ieso.ca/en/Sector-Participants/Market-Renewal/Market-Renewal-Incremental-Capacity-Auction

[14] As part of existing Capacity Market design and rules, and as presently being planned for ICAs, demand curves are established as a series of capacity price caps commensurate with different quantities of capacity. The main component to derive demand curves is the net cost of new entry (CONE), where net CONE is 'net' of energy and ancillary services prices and revenues.

LMPs will be set are contained within Appendix 7.5 of Chapter 7 in the IESO Market Rules[15]. This Appendix provides the detailed technical rules, equations, and variables used to formulate schedules, dispatch instructions, and set market clearing prices.

A good example of the applicability of other inputs in setting market clearing prices comes from 2007 when the IESO proposed amendments to Section 4.13.1 of Appendix 7.5 of Chapter 7 (i.e., MR-00331[16]). These amendments to the IESO Market Rules were implemented to re-define the parameter that controls the ramp rate multiplier used in setting HOEPs and MCPs. At that time, the IESO stated that "the existing market rules authorize the IESO to establish that parameter but do not define its value. Prior to market commencement in 2002, the IESO set the parameter such that the ramp rate multiplier used for pricing was 12-times the actual ramping capability of Ontario generation facilities. That value was intended to be temporary"[17]. The IESO's use of a 12-times ramp rate resulted in less volatile market clearing prices and suppressed HOEPs and MCPs. MR-0331 proposed to replace 12-times ramp rate with 3-times ramp rate. The IESO provided rationale for this change by stating that "moving to a three-times ramp rate multiplier would improve the quality of market signals to all consumers and producers, and would immediately address some concerns expressed by the Ontario Energy Board's Market Surveillance Panel about market inefficiencies …"[18] The IESO implemented MR-0331.

The above example clearly shows that other inputs and factors will impact how LMPs will be set in the future[19]. This example also questions how the IESO will make decisions on exercising their rights to set such parameters (e.g., how will ramp rates impact setting LMPs[20]).

Specific Comments on Draft SSM HLD – Operations and Impacts on Consortium Member Facilities and Projects

Supplier Pricing – Negative LMPs Will Impact Operations with Contract Implications

Implementation of LMPs will 'unlock' more frequent and lower negative wholesale energy prices compared to HOEPs and MCPs. Based on historic wholesale energy shadow prices (i.e., proxy for LMPs)

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[15] See http://www.ieso.ca/en/Sector-Participants/Market-Operations/Market-Rules-And-Manuals-Library

[16] See http://www.ieso.ca/Sector-Participants/Change-Management/Market-Rule-Amendment-Archive-Pre-2012

[17] See MR-00331-R00 Market Rule Amendment Proposal

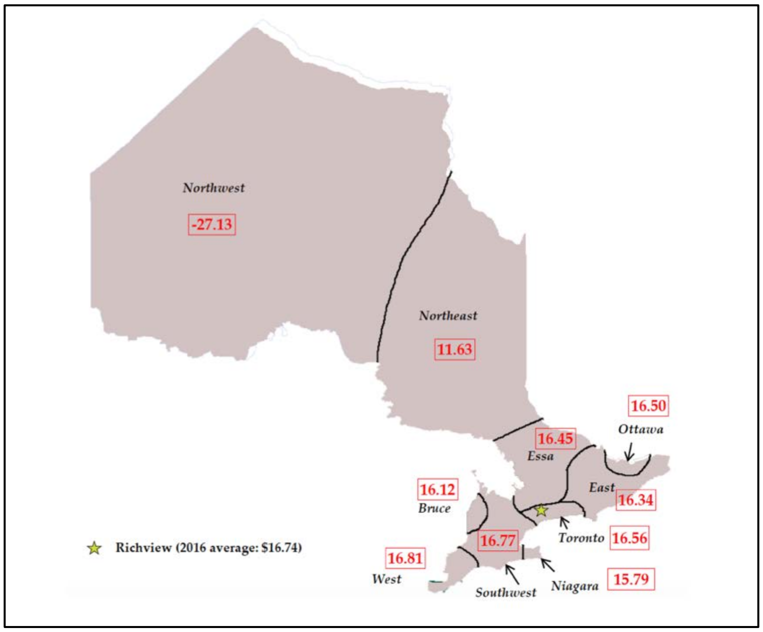
[18] See MR-00331-R00 Market Rule Amendment Proposal

[19] This example does not suggest that it will be specifically applicable to LMPs going forward within Energy Workstream detailed design consultations (it may or may not). It is meant to simply convey that other factors will impact the calculations of LMPs.

[20] In today's IAM, HOEP and MCP are set using 3-times ramp rate whereas the 'shadow prices' (i.e., proxies for LMPs) resulting from the IESO's dispatch optimization are based on 1-times ramp rate – which in part explains why shadow prices are much more volatile and at times very high or low compared to applicable HOEPs and MCPs

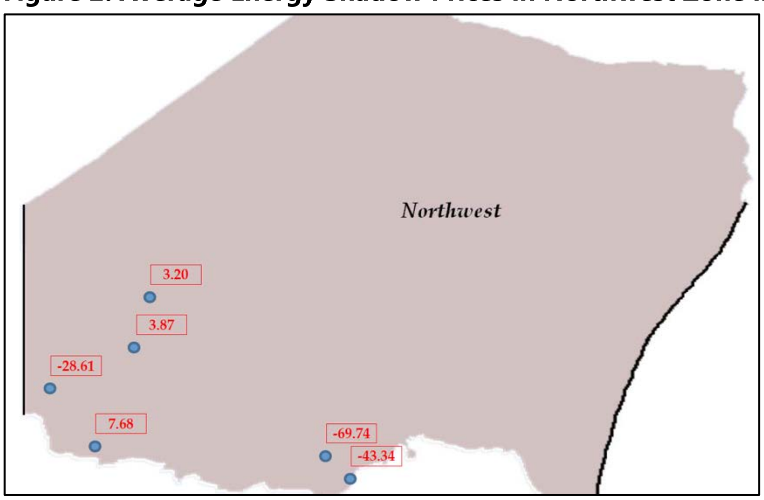
averaged by the IESO's defined 10 transmission zones, negative prices have been much more prevalent in the northwest zone followed by the northeast zone when compared to all southern zones. Figure 1 shows the wide range of negative prices across these zones, and Figure 2 provides more granularity within the northwest zone.

Figure 1: Zonal Prices in 2016



Source: IESO Single-Schedule Market Materials, September 21, 2017

Figure 2: Average Energy Shadow Prices in Northwest Zone in 2016



Source: IESO Single-Schedule Market Materials, September 21, 2017

Based on the projected demand/supply balance in the northern zones, negative wholesale energy prices are expected to be more prevalent in the northwest zone compared to the current HOEPs and MCPs. As a consequence, implementation of LMPs will result in two issues that will need to be addressed during the Energy Workstream detailed design consultations: (i) operations and price signals within the IAM; and, (ii) contract amendments. These issues are detailed below.

Negative LMPs Will Create Operational Challenges with Potential to Distort Price Signals in the IAM

When wholesale energy prices are negative, this indicates that supply is greater than demand. Therefore, suppliers (e.g., generators) do not have economic incentives to produce energy. Under specific circumstances (e.g., water management), suppliers may elect or need to produce energy during negative priced intervals, therefore resulting in suppliers paying the negative wholesale energy price to produce energy. However, for example, when wholesale energy prices are negative for multiple dispatch intervals and hours, it will not be reasonable for suppliers to consistently pay to produce energy. Under such a scenario, generators will not operate. This will create operational challenges for these generators to quickly respond to supply needs as indicated by positive wholesale energy prices. For example, if load requires supply near the Thunder Bay LMP in the northwest zone as indicated by positive LMPs for a few contiguous five-minute dispatch intervals, generators may not be operationally ready nor capable to meet this supply if they had been shut down due to negative LMPs as a result of multiple contiguous hours previous to the positive LMPs. Further, if only a few contiguous intervals project to result in positive LMPs, it may not be economic for applicable generators to operate to only receive revenues for a very short duration of dispatch intervals.

Overall, it will be challenging for suppliers to react to more frequent negative LMPs (i.e., should generators continue to operate at minimum levels, ramp units down, shutdown units, when to schedule maintenance of units, etc.). When wholesale energy prices are negative, these price signals are challenged to accurately convey actual demand/supply balance (other than for general oversupply conditions) and in part not providing clarity as to how suppliers should operate (e.g., likely will be difficult to determine how oversupplied a specific location on the grid may actually be, how other MPs (suppliers and loads) may react, etc.).

Negative wholesale energy price implications have the potential to be exacerbated resulting from some contract drivers and incentives. Nearly all contracts with renewable generators registered as MPs (e.g., RES, FIT, LRP, HCI) incent these generators to produce energy in order to be paid under their contracts[21]. Further, some of these contracts afford protection against negative wholesale energy prices but depending on contract amendments that will result from forthcoming amendments to the IESO Market Rules to implement LMPs, some generators may be contractually incentivized to submit very low offer prices (e.g., trending to the present Minimum Market Clearing Price of $-2,000/MWh) in order to increase the likelihood of being dispatched to produce energy in order to be paid under their contracts. As a

[21] For purposes of making the point, applicable Contract Amendment Agreements to address risk of curtailment of energy production were not factored in, but the example would still hold if curtailment were factored in

consequence, LMPs will then be even more negative than they otherwise would be without such offer price incentives driven by specific contract provisions. Under this scenario, price signals will be distorted even further through much lower negative LMPs.

On behalf of select Consortium members with generators in the northwest and northeast zones, Power Advisory LLC has conducted a high-level impact analysis to wholesale energy market and contract revenues if these generators had been settled on an applicable LMPs. Analysis results concluded that all of these generators would have earned less revenues based on the combination of revenues from the IAM and contracts. Therefore, this analysis suggests that generators that will be exposed to frequent negative LMPs will be financially harmed.

To date, the SSM stakeholder consultation has not addressed any negative wholesale energy pricing issues. The draft SSM HLD is correct in identifying in Section 2.6.3 that negative pricing will be addressed during Energy Workstream detailed design consultations. The IESO is encouraged to make negative pricing a top priority issue for the reasons expressed above.

<u>Amendments to IESO Market Rules Relating to Implementation of LMPs Will Trigger Contract Amendments with Implications for Operations within the IAM</u>

The Consortium commends the IESO on their early and consistent effort to engage with contract counterparties regarding future contract amendments that will be triggered by amendments to the IESO Market Rules relating to MRP design components (e.g., SSM, DAM, ERUC). We are further pleased with the IESO's present position, that was first stated during their October 31, 2017 webinar and stated many times during subsequent meetings with contract counterparties, that during contract amendment negotiations the IESO will not look to "extract value from contracts". However, the Consortium does not agree with the IESO's initial thought that many of the renewable generator contract amendments will be "mechanical" (i.e., simple or straightforward). On the contrary, the Consortium believes that implementation of LMPs and elimination of CMSC will result in complicated contract amendments to restore "Supplier's economics" as contemplated under all applicable contracts[22]. The following two examples convey this point.

First, as discussed in early sections within this submission, generators that face negative LMPs (e.g., generators located within the northwest zone) will earn less revenues from the IAM and their contracts. This is a function of either being dispatched less and/or being settled at negative market clearing prices. This will need to be reconciled.

[22] Applicable to all contracts with provisions to restore "Supplier's economics" (e.g., see FIT Contract Version 1.5.1, Section 1.7(a))

Second, with the elimination of CMSC (specifically constrained-off payments), foregone energy calculations and payments in applicable Contract Amendment Agreements[23] will be negatively impacted. Supplier's economics will need to be restored to continue mitigating renewable generators from energy production curtailment risks[24]. For example, using FIT Contract Version 1.5.1, amendments to the IESO Market Rules to implement LMP and eliminate CMSC will impact the Contract Amendment Agreement settlement calculations for compensation of foregone energy. This is shown below by simplifying applicable settlement equations[25].

> Contract Amendment Payment for Foregone Energy =
> [(Foregone Energy Payment) + (Interval Negative Price Amount Payment)] –
> [(Excluded Delivered Electricity Payment) + (CMSC Constrained-Off Payment)]

Elimination of CMSC will result in contract amendments to the Interval Negative Price Amount Payment and CMSC Constrained-Off Payment variables in the above equation.

Supplier Pricing – Elimination of CMSC Payments Have Implications for Power System Operations and Contract Amendments

CMSC payments (specifically constrained-off payments) are the primary mechanism to financially incent suppliers to not produce energy when Ontario's power system does not require additional energy supply. While it is acknowledged that all other North American wholesale electricity markets (except AESO) administer LMP pricing regimes without constrained off payments[26], constrained-off payments have been used as a mechanism to help manage scheduling and dispatch of energy production in Ontario. Considering projected oversupply in the northwest zone, the IESO will need to develop specific mechanisms through the Energy Workstream detailed design consultations to help manage scheduling and dispatch of energy production in the northwest zone and perhaps the northeast zone. This will necessarily require a 'made in Ontario' solution, as no other North American wholesale electricity market

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[23] Contract Amendment Agreements refer to contract amendments to applicable contracts (e.g., RES I, RES II, RES III, FIT, etc.) to address economic curtailment of energy production from MP variable (i.e., wind and solar) generators

[24] In 2013 as part of SE-91, proposed rule amendment MR-00381 was developed to enable 5-minute dispatch of all transmission-connected variable generators and all embedded variable generators registered as MPs. With respect to curtailment of energy production, two consequences resulted from MR-00381: (i) variable generators at times are not dispatched to produce energy, even though fuel is available to produce energy; and, (ii) variable generators that already are producing energy at times receive dispatch instructions to produce less energy within future dispatch intervals. Based on provisions in the majority of renewable generation contracts, the Ontario Power Authority was required to compensate affected variable generators for foregone energy production resulting from the implementation of the SE-91 and MR-00381.

[25] For purposes of clearing making the point, the equation is accurate but simplified

[26] However, all of these wholesale electricity markets provide make-whole payments

is experiencing or is projected to experience the same level of negative wholesale energy pricing compared to LMPs in the northwest zone.

Market Power Mitigation – Ex-Ante Mitigation of Economic Withholding Requires Thoughtful Design with Recourse for MPs and Physical Withholding Will Not be an Issue Due to Contract Incentives

All wholesale electricity markets have rules and protocols for assessing and mitigating market power. Therefore, the IESO is correct in exploring changes to Ontario's market power mitigation framework to assess and mitigate for economic and physical withholding. The sub-sections below provide additional comments on the IESO's proposed market power mitigation framework.

<u>Ex-Ante Economic Withholding Tests Must be Reasonable and Permit MPs with Sufficient Recourse When Disagreements Arise</u>

The IESO is proposing to implement ex-ante Conduct & Impact Tests to assess and mitigate for economic withholding (i.e., pricing energy production above short-run marginal costs). While the IESO's logic is sound in proposing to implement an ex-ante test as opposed to an ex-post test, considerable caution is required in establishing Conduct & Impact Tests.

Conduct & Impact Tests are predicated on establishing a series of thresholds (i.e., supplier ability to exercise market power) to determine when these tests will be applied and under what conditions these tests will be violated (e.g., offer prices exceed pre-determined reference levels) therefore signaling that economic withholding is being exercised. The following are recommendations regarding Conduct & Impact Tests:

- Full transparency regarding methodologies that will be used to determine thresholds and reference levels;
- Thresholds and reference levels should not be static and will need to change over time to most accurately reflect changing power system conditions and applicable costs (e.g., fuel, etc.);
- Rules and protocols where mitigation will not be applied under circumstances where violations to reference levels are justified (e.g., fuel scarcity, substantiated higher costs, etc.); and,
- Clear and effective rules and protocols for justified recourse when MPs do not agree with the IESO's application of Conduct & Impact Tests leading to mitigation.

Regarding the last point above, the Consortium is pleased that the IESO Board of Directors has appointed a stakeholder Advisory Group to provide recommendations on needed reforms to the governance and decision-making framework within the IAM[27], and looks forward to positive reforms to be determined in

[27] See http://www.ieso.ca/Sector-Participants/Engagement-Initiatives/Engagements/IESO-Governance-and-Decision-Making

the coming months. Reforms to the governance and decision-making framework must address shifting risks to MPs resulting from implementation of MRP (e.g., Conduct & Impacts Tests, etc.).

Overall, market power mitigation is closely linked to the points made earlier in this submission regarding price fidelity. There is a fine line between the need to exercise market power mitigation versus permitting the wholesale energy market to work through prices that accurately reflect demand/supply conditions yielding commensurate wholesale energy market revenues that value meeting power system needs. In other words, overly and unnecessarily mitigating MPs can lead to price suppression which may not accurately value power system needs and requirements.

<u>Physical Withholding Does Not Project to Be an Issue Within the IAM</u>

The IESO is correct in stating within the draft SSM HLD that assessment of physical withholding (i.e., MPs not offering available energy supply) should be done ex-post and not ex-ante.

Physical withholding does not project to be an issue within the IAM because the vast majority of generators are incented to offer energy into the IAM through contract provisions. As stated earlier in this submission, the contracts with renewable generators incent these generators to produce energy to be paid under their contracts. Further, contracts for gas-fired generators either have settlement logic that works to incent these generators to produce energy and not withhold production or have energy 'must-offer' provisions in the IAM. Finally, the majority of Ontario Power Generation's (OPG's) generators are rate-regulated by the OEB, and have incentives built into their regulatory requirements to produce energy and not withhold production.

Make-Whole Payments – Elimination of CMSC Payments Necessitates Need for Make-Whole Payments in Addition to Being a Needed Mechanism to Address Power System Operation Needs

Make-whole payments will be required under circumstances where resources are dispatched up or down 'out of merit' (i.e., dispatched down when economic or dispatched up when not economic, relative to other resources).

While the magnitude of make-whole payments (i.e., frequency and quantum) may not project to be as high as CMSC payments, this point will likely be true within the southern zones but not necessarily for the northern zones in Ontario. That is, depending on final decisions to address negative wholesale energy pricing in the northern zones (particularly the northwest zone), make-whole payments may factor more in the northern zones than the southern zones. Therefore, make-whole payments should be a key priority during the Energy Workstream detailed design consultations.

Detailed Comments on Draft SSM HLD

Listed below are detailed comments corresponding to applicable sections within the draft SSM HLD.

Executive Summary

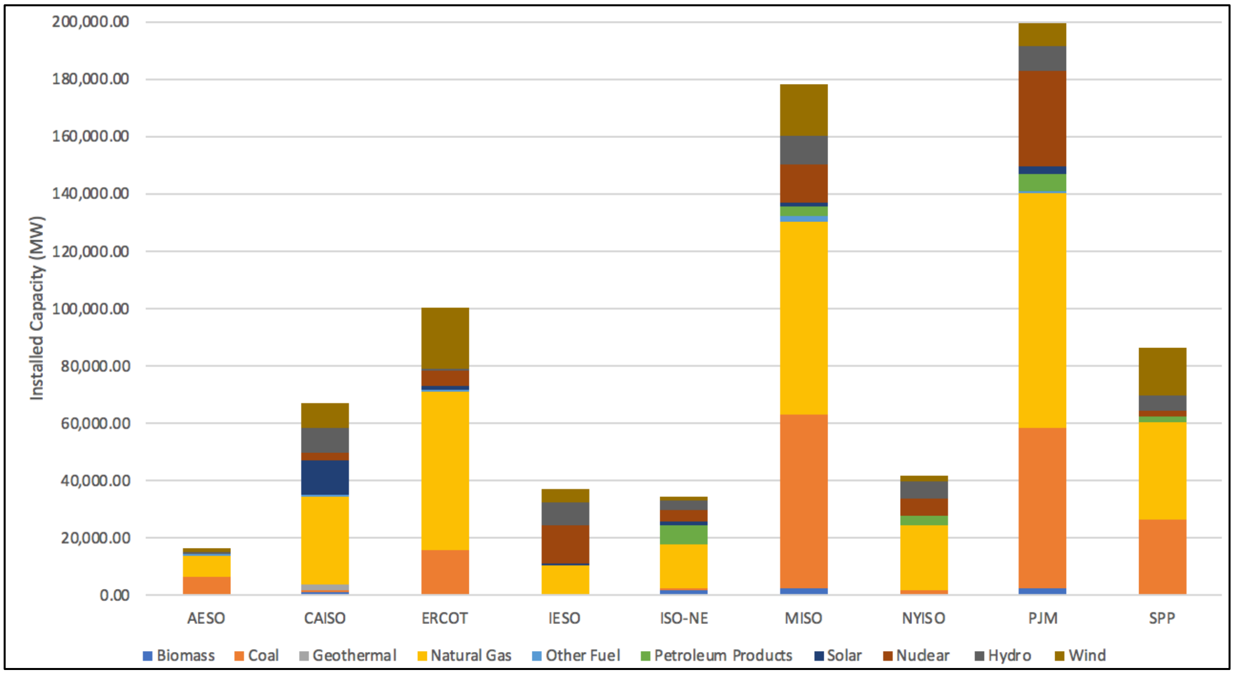
On balance, the Consortium is supportive of the IESO's MRP and believes that the IAM must evolve. We have general comments about some of the IESO's declarations regarding the MRP.

First, p.1 of the draft SSM HLD states that "the IESO committed to a made-in-Ontario approach", but there has been little evidence thus far within the stakeholder consultations that this is actually the case. In fact, given the scope of draft HLD for the SSM, and likely draft HLDs for DAM, ERUC, and ICAs, it very much appears that the IESO is replicating the blueprint of what is known as U.S. Standard Market Design (SMD). U.S. SMD has generally been defined as a financially-binding DAM, Security Constrained Unit Commitment (i.e., ERUC), and LMPs for energy and OR in the DAM and real-time market (RTM), and where Capacity Markets exist capacity is typically defined as Unforced Capacity (UCAP) and settled on a forward basis (i.e., months or years). The IESO has not been sensitive enough to addressing fundamental differences within the IAM compared to U.S. wholesale electricity markets. The Consortium recommends that the following Ontario-specific differences need to be addressed within the MRP, including but not limited to:

- Relatively higher share of baseload generation capacity and energy supply (i.e., nuclear, hydroelectric, variable generators);
- Relatively higher share of hydroelectric generators located on cascade river systems and relatively more storage capabilities;
- Relatively higher share of variable generators compared to relatively lower share of coal-fired and gas-fired generators; and,
- Relatively higher share of resources (e.g., generators) under contract with the IESO and OPG's rate-regulated assets (i.e., nuclear and applicable hydroelectric generators, and pump storage).

These fundamental Ontario-specific differences (Figures 3 and 4 show changes in supply mix by wholesale electricity market) must be effectively factored into the applicable HLDs and Detailed Designs (DDs) for SSM, DAM, ERUC, and ICAs.

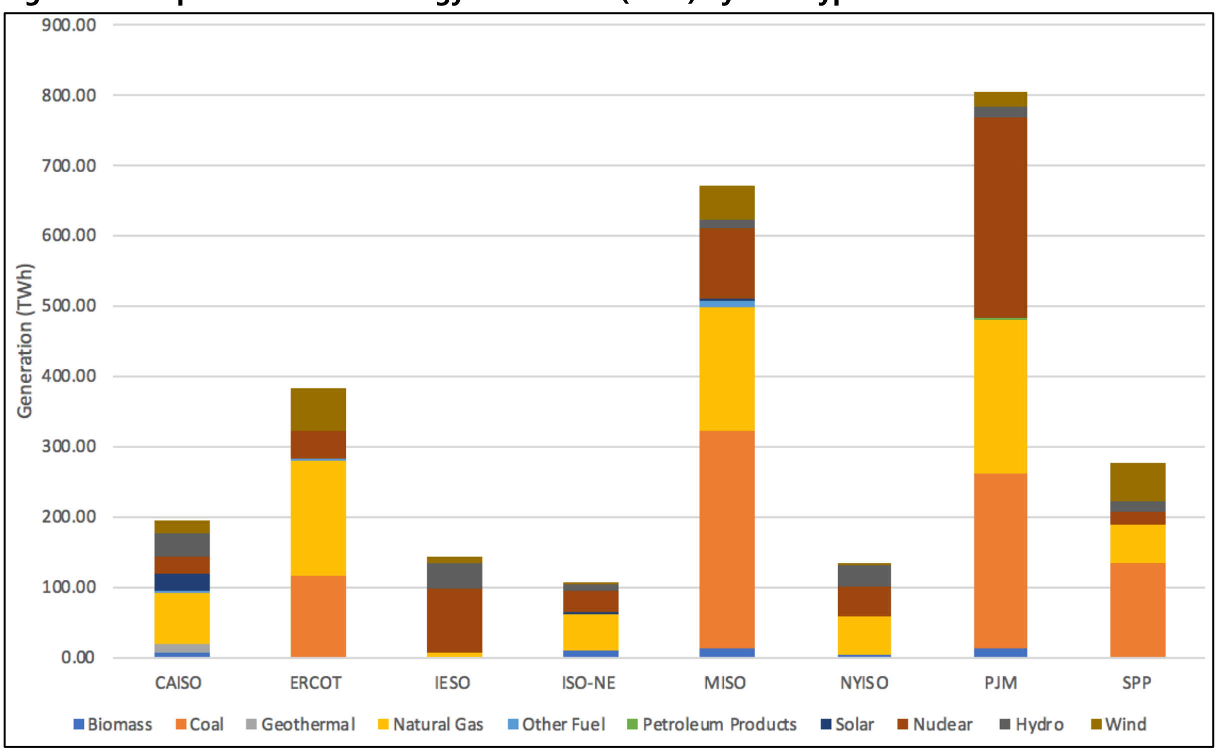
Figure 3: Comparison of 2018 Installed Capacity (MW) by Fuel Type



Sources: S&P Global Market Intelligence (SNL), IESO, AESO

Note: AESO data shown is for 2017

Figure 4: Comparison of 2017 Energy Production (TWh) by Fuel Type



Sources: S&P Global Market Intelligence (SNL), IESO

Second, p.1 of the draft SSM HLD suggest that "general consensus on important high-level design decisions" has been achieved to date. The Consortium does not agree with this position. While the Consortium is not aware of any specific MP or stakeholder that opposes the MRP, we note that very little written comments have been submitted to the IESO to date resulting from their MRP stakeholder consultations and proposed HLD decisions. Therefore, we believe this IESO claim has been made prematurely.

Third, p. 2 of the draft SSM HLD states that "implementing an … (ICA) … will drive down costs by encouraging greater competition in acquiring the resources to meet system needs". There are two concerns with this claim. One, very recent examples from the ISO-NE Capacity Market suggests this market is being challenged to procure resources needed to maintain reliability[28], and new projects that cleared this market are having issues achieving required permits and approvals to develop these projects and therefore do not project to be able to meet their capacity obligations[29]. Two, at the IESO's September 12, 2018 ICA consultation meeting[30] and at the September 13, 2018 technical power system planning meeting[31], the IESO clearly expressed concerns that initial ICAs may not effectively facilitate development of needed new projects (i.e., IESO projects Ontario to require approximately 1,400 of capacity in 2023 and 3,700 MW in 2025). Therefore, given these points and recent IESO declarations, it is clearly speculation that ICAs themselves will drive down costs in acquiring resources to meet Ontario's power system needs.

Price Formation: Pre- and Post-Interval Pricing (Section 2.4)

The IESO's decision to calculate LMPs ex-ante is sound as this methodology will align best with dispatch instructions which are provided to MPs ahead of dispatch intervals.

Consistent with points raised above regarding price fidelity, energy demand forecasts can impact LMPs where p. 13 of the draft SSM HLD states that "Under ex-ante pricing, both … dispatch and … pricing … take place prior to the interval and use the same set of inputs, including forecasted Ontario demand". It will be important during the Energy Workstream detailed design consultations to determine which energy demand forecast will be used to help set LMPs (e.g., peak demand forecast, average demand forecast,

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[28] See Appendix B for a brief description of present issues regarding Exelon's request to de-list generating units at the Mystic generation facility, combined with ISO-NE's refusal to permit these units to de-list, and present issues before the U.S. Federal Regulatory Energy Commission (FERC)

[29] See Appendix B for a brief description of issues Invenergy is presently experiencing in developing their New England based gas-fired generation project and potential for this project to not meet its capacity obligations

[30] See http://www.ieso.ca/Sector-Participants/Market-Renewal/Market-Renewal-Incremental-Capacity-Auction

[31] See http://www.ieso.ca/en/Sector-Participants/Planning-and-Forecasting/Technical-Planning-Conference

etc.). There have been issues within the present IAM resulting from the IESO's use of peak demand forecasts in the pre-dispatch timeframe and actual demand in real-time to determine ex-post pricing[32]. As a consequence, when the peak demand forecast has been used in pre-dispatch the IESO has, at times, been over-forecasting energy demand ahead of real-time dispatch which can result in over-committing resources which has the result of lowering real-time HOEPs and MCPs relative to pre-dispatch prices for the same dispatch hour.

Overall, the IESO needs to be consistent with its application of energy demand forecasts along with the impact of demand forecasts on wholesale energy prices.

Price Formation: Intertie Congestion Pricing (Section 2.5)

The Consortium encourages the IESO to continue working towards market design, rules, and intertie transaction protocols that best aligns with economic drivers and market incentives for MPs to efficiently schedule and price their intertie transactions.

Consistent with this point, the Consortium is not convinced of the rationale behind proposing different treatment of imports and exports using the dynamic Intertie Congestion Prices (ICPs) for imports and static ICPs for exports. With respect to the IESO's rationale regarding export transactions, it appears that the IESO's proposed use of static ICPs, as stated on p. 16 of the draft SSM HLD, is that "pre-dispatch prices are persistently higher than prices at the same location in real-time. Causes of this difference include the use of peak demand forecasts in some hours". The Consortium notes that this rationale may be premature considering that no design decisions have been made regarding the applicability of pre-dispatch in light of developing DAM and ERUC, and if applicable, what energy demand forecast will be used in pre-dispatch (i.e., it is not clear whether this issue will exist if average demand forecasts are used in pre-dispatch rather than peak demand forecasts).

On p. 17 of the draft SSM HLD, the IESO states that "A single intertie with a neighbouring jurisdictions can be composed of multiple transmission lines that connect to different locations on the grid. Each of these connection points could be subject to different LMPs". The Consortium is of the general view that different LMPs should correspond to different intertie connection points.

Transmission Rights (TRs) have not been discussed during the SSM stakeholder consultations and the IESO acknowledges on p. 17 of the draft SSM HLD that they are "planning to review design changes and the impact of TR market development". The Consortium supports this point and TRs should be developed to provide hedges to MPs transacting on interties resulting from intertie congestion. The Consortium

[32] It is acknowledged because of past issues that the IESO made modifications to implement rules/protocols when peak demand forecasts are used in pre-dispatch as opposed to average demand forecasts (i.e., trying to use the demand forecast most likely to closer reflect actual demand forecast in real-time).

does not understand why the IESO has not referred to TRs as Financial Transmission Rights (FTRs). FTRs is a more appropriate term, assuming that the IAM market design for intertie transaction are to remain without the need of physical intertie reservations[33].

Price Formation: Supplier Pricing (Section 2.6)

The IESO states on p. 19 of the draft SSM HLD that "the SSM will align … prices paid to suppliers with their dispatch instructions … Aligning prices with dispatch encourages suppliers to offer at their short-run marginal cost without the need for complex set of out-of-market uplift payments". As a general point, this statement is correct. However, it is overly simplistic because there are more factors that need to be worked through within the Energy Workstream detailed design consultations to really understand how closely LMPs will be aligned with dispatch instructions and therefore determining how often out-of-market uplift payments may occur and their magnitude. For example, earlier in this submission a list of factors were identified that have not been discussed within the SSM consultations and yet have potential to create mis-alignments between LMPs and dispatch instructions, therefore having potential to expand make-whole payments.

Regarding the detailed design considerations listed on p. 19 of the draft SSM HLD, the IESO is correct in identifying the need to evaluate potential issues with negative wholesale energy prices and the need for potential options to address solutions. As stated earlier in this submission, the Consortium believes that negative wholesale energy pricing will be an issue predominantly in the northwest zone, and should be positioned as a high priority design component that must be sufficiently addressed within the Energy Workstream detailed design consultations.

Price Formation: Operating Reserve Reference Price (Section 2.7)

As stated on p. 21 of the draft SSM HLD, the Consortium supports the IESO's decision "to continue to calculate the OR reference price by jointly optimizing energy and the three categories of OR".

However, consistent with the points made earlier in this submission regarding price fidelity, the Consortium recommends that the during the Energy Workstream detailed design consultations that the IESO explore potential to design and implement an OR Demand Curve (ORDC) similar to what has been implemented in ERCOT. An ORDC is a mechanism that prices scarcity value of OR with considerations to the simultaneous value and price of energy.

On June 1, 2014 ERCOT implemented the ORDC which created a Real-Time Price Adder within the Texas wholesale electricity market reflecting the value of available reserves in the RTM. This reflects the Value of

[33] That is, maintaining the present design of Ontario's interties managing congestion 'financially' rather than 'physically' with commensurate physical transmission rights

Lost Load (VOLL) based on the probability that load would have to be shed. Based on implementing the ORDC, real-time energy prices increase automatically as OR decreases. In other words, the ORDC ensures that wholesale energy prices reflect the increasing value of energy when the possibility of outages increases. Therefore, when the Loss of Load Probability (LOLP) increases, the ORDC will increase accordingly. When OR falls to 2,000 MW or less, the ORDC will automatically adjust energy prices to the established VOLL (presently set as the ERCOT's System-Wide Offer Cap (SWOC) of $9,000/MWh ($US))[34].

Price Formation: Constraint Violations (Section 2.9)

Determining the rules and protocols when constraint violations will be binding, when they will be relaxed, and when a binding constraint can set market clearing prices are all directly linked to the points made earlier in this submission regarding price fidelity. Therefore, it is important for the IESO to develop and apply rules and protocols that permit LMPs to accurately reflect actual demand/supply conditions, including scarcity as indicated by constraints nearly being violated or violated.

On p. 23 of the draft SSM HLD, the IESO needs to better explain how the present penalty prices per constraint violations have been established, under what conditions have these constraints been relaxed, and what were the resulting wholesale energy and OR pricing implications. This will better inform future discussion within the Energy Workstream detailed design consultations.

On p. 24 of the draft SSM HLD, the IESO has decided to maintain the existing Maximum Market Clearing Price (MMCP) of $2,000/MWh. In light of the points being raised in this submission regarding price fidelity, the Consortium recommends that the IESO review the MMCP during the Energy Workstream detailed design consultations. It is noted that other wholesale electricity markets have transitioned to a much higher MMCP. For example, ERCOT's SWOC (i.e., similar to MMCP) has been steadily raised to $9,000/MWh ($US) in 2015 from $2,250/MWh ($US) in 2011, as illustrated in Figure 5. The main driver for the SWOC increases were to encourage new generation development to maintain Texas' reserve margin and resource adequacy.[35]

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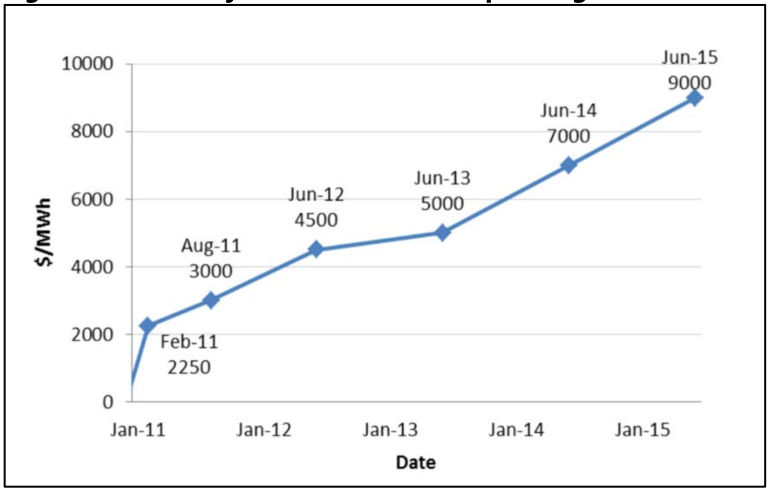
[34] See https://hepg.hks.harvard.edu/files/hepg/files/ordcupdate-final.pdf for further details on the ORDC

[35] https://www.greentechmedia.com/articles/read/ercot-will-raise-texas-system-wide-offer-cap-to-9000-in-2015#gs.OurH5UE

Figure 5: ERCOT System Wide Offer Cap Changes



Source: "Scarcity Pricing in ERCOT" Presentation[36] to FERC Technical Conference, 2016

Overall, the IESO is correct in stating that a new set of penalty prices will need to be worked through and created for pricing reliability-based constraints and non-reliability-based constraints. As suggested earlier in this submission, principles relating to price fidelity should help guide such penalty pricing discussions and decisions to be made within the Energy Workstream detailed design consultations.

Price Formation: Out-of-Market Operator Actions (Section 2.10)

The IESO is correct in pointing out that out-of-market actions (i.e., "control actions") taken by the IESO's control room operators can impact how market clearing prices are set, and there needs to be changes to ensure that control actions are reflected within market clearing prices.

On p. 26 of the draft SSM HLD, the IESO states that "control actions taken to address reliability concerns during scarcity conditions should impact dispatch, but be prevented from impacting price". The Consortium does not agree with this point, and that exercising control actions during scarcity conditions should impact both dispatch and price. This point does not seem to be consistent with some of the IESO decisions listed on p. 27 that appear to permit applicable reliability-based control actions to impact dispatch and price.

The Consortium recommends that the IESO should re-cast Table 2 on p. 27 of the SSM HLD to list all control actions in sequential order to which the IESO control room operators may activate such actions, and clearly link each control action's impact on dispatch and price. By adding to and re-ordering the control actions list, MPs and stakeholders will be able to better understand how control actions are

[36] https://www.ferc.gov/CalendarFiles/20160629114652-3%20-%20FERC2016_Scarcity%20Pricing_ERCOT_Resmi%20Surendran.pdf

applied and what impact these actions have on dispatch and price. Consistent with points made earlier in this submission regarding price fidelity, on balance, market clearing prices should increase with each commensurate control action 'going down the list' so as to reflect the use of control actions to meet the severity of Ontario's powers system reliability needs.

Price Formation: Price-Setting Eligibility/Operating Restrictions (Section 2.12)

The IESO states on p. 31 of the draft SSM HLD that "Ontario … does not have the types of fully block-loaded intra-hour units that have caused most of the pricing concerns in other jurisdictions. Ontario's current intra-hour units have significant dispatchable ranges above their MLP [minimum loading point], allowing them to set LMP … in 2016 the IESO found that Ontario's intra-hour units were scheduled for more than 200 MW, but not setting price, in only 1% of intervals … Based on this assessment … the IESO has determined that it will not allow the MLP output … to set LMPs".

The Consortium questions this decision because the analysis was conducted using 2016 data and information. Power system conditions in 2016 reflected significant surplus baseload generation (SBG), therefore Ontario's intra-hour generating units would naturally be scheduled infrequently and will not set market clearing prices often. However, post implementation of SSM, DAM, and ERUC (planned by the IESO for 2022 implementation), Ontario projects to have much less SBG mainly due to planned retirements and refurbishments of nuclear generating units. Therefore, the Consortium recommends that the IESO review their decisions and undertake another analysis aligned with the planned timing to implement SSM, DAM, and ERUC within the Energy Workstream detailed design consultations.

Market Power Mitigation

On p. 33 of the draft SSM HLD, the IESO states that "As part of the detailed design phase … IESO will … develop new processes, or amend existing ones related to how market participants interact with the mitigation framework. Such interactions may include … dispute of mitigation decisions". The Consortium is pleased that the IESO has acknowledged that there could be times when MPs dispute the IESO's mitigation decisions. Therefore, this point further supports the work the IESO is doing with their Advisory Group to reform the governance and decision-making framework within the IAM, which includes review of the present dispute resolution framework detailed within the IESO Market Rules.

Market Power Mitigation: Mitigation Process (Section 3.2)

On p. 37, the IESO states that "the conduct and impact thresholds will be higher in areas with significant competition and lower in areas where competition is restricted". The Consortium agrees with this position in principle but is not sure how this principle will practically be applied for the northern zones (particularly the northwest zone). The northern zones have a very specific set of circumstances that likely need particular attention when developing applicable Conduct & Impact Tests. For example, these zones are transmission constrained, may have pivotal suppliers by way of share of generation ownership, generally oversupplied, project to have relatively more negative wholesale energy prices (compared to southern zones), and some contracted generators are contractually afforded negative price protection. Due to these very unique set of circumstances, it may be challenging to develop appropriate Conduct & Impacts Tests for the northwest zone. An example of why this may be challenging could result from potential drivers for some resources located in the northwest zone to exercise market power to *lower* market clearing prices, so as to deter other resources from being economically dispatched. Therefore, the Consortium believes that the IESO is correct in listing the need to "Consider and account for Ontario-specific issues that could otherwise significantly impact the efficiency of the mitigation regime" as the second proposed guideline to develop conduct and impact thresholds listed on p. 37 of the draft SSM HLD.

On p. 38 of the draft SSM HLD, the IESO states that "The IESO will only apply mitigation on the interties when competition is restricted or the intertie is deemed and designated to be uncompetitive". The Consortium notes a few important points related to this position. First, because of the nature of radial interties with Quebec, very few MPs transact on these interties. This position then suggests that transactions on radial interties should always be subject to market power mitigation. Second, the IESO has an existing contract with Hydro-Quebec[37]. Does this contract create an uncompetitive intertie(s) between Ontario and Quebec with Hydro-Quebec having market power on this intertie(s)? If so, how will this be reconciled with the position of applying market power mitigation on uncompetitive interties?

Given that Ontario has approximately 5,000 MW of intertie capacity, global market power is likely to not be an issue within the IAM. Therefore, the Consortium recommends a straightforward and reasonable market power mitigation framework to address any exercise of global market power.

Market Power Mitigation: Reference Levels (Section 3.3)

Due to relatively low short-run marginal costs of the resources owned and operated by the Consortium members (i.e., mainly wind, hydroelectric, and solar generators) mainly resulting from very low fuel costs, short-run marginal costs for these resources may more so be driven by opportunity costs. Therefore, in establishing applicable reference levels for the majority of the Consortium member's facilities, it is not yet clear how opportunity costs will be determined. This likely will represent a key focus for the Consortium during the Energy Workstream detailed design consultations regarding developing applicable reference levels for Conduct & Impacts tests for wind, hydroelectric, and solar generators.

[37] See https://www.fao-on.org/en/Blog/Publications/Electricity-Trade-0418 for available information on the existing IESO-Hydro-Quebec supply contract

Load Pricing (Section 4)

Considering that members of the Consortium represent energy storage stakeholders and are developers/owners/operators of energy storage projects, the following comments relate to the withdrawal of energy from the IESO-Controlled Grid (ICG) for the purposes of storing energy.

On p. 43 of the draft SSM HLD, the IESO states that "The decisions discussed in this section [Section 4.1] will not directly affect how the majority of loads in the province … are billed for electricity". The Consortium believes this statement to be premature in making this assumption, considering that no decisions have been made regarding any causal changes to rates (e.g., RPP) and charges (e.g., GA) relating to the design and planned implementation of an LMP pricing regime. Any potential changes to rates and charges to load customers (e.g., energy storage based on withdrawal of energy) will impact the economics of the application of energy storage within Ontario.

On p. 43 of the draft SSM HLD, the IESO states that "An accurate price signal can encourage market participant loads that are price-sensitive … to reduce consumption from the IESO-controlled grid when local prices are relatively high". While this statement is true, the accuracy of rates and charges relative to the local value and price of energy also encourages how energy is consumed. This is particularly important for energy storage when used to help manage, and at times lower, energy costs. For example, energy storage is being deployed within Ontario to assist qualified industrial and large commercial customers to avoid GA charges during critical peak energy demand hours within a given year.

The above points are particularly important regarding the IESO's proposed decision to charge all non-dispatchable loads (NDLs) zonal energy prices by way of aggregating applicable LMPs within respective zones. Because it is not yet clear how rate design may potentially change and how GA may be allocated resulting from planned implementation of an LMP pricing regime, energy storage resources embedded within NDLs (e.g., Local Distribution Company (LDC) service territory) may not be economical depending on future decisions regarding rate design and allocation of charges. As a potential consequence, specific benefits that can be provided by many energy storage resources (e.g., quick-response to produce energy, ancillary services, etc.) may not be realized depending on decisions still to be made regarding rate design (e.g., RPP) and allocation of charges (e.g., GA).

The Consortium also notes that decisions regarding the above points will also have economic implications on how congestion rents and loss residuals are distributed to load customers. Methodology how congestion rents and loss residuals are distributed to load customers will also impact the economics of some energy storage resources.

Settlement Topics: Make-Whole Payments (Section 5.1)

On p. 53 of the draft SSM HLD, the IESO states that "Compared to the current two-schedule market, the need for make-whole payments in an SSM is expected to be infrequent and immaterial". Based on experience in other wholesale electricity markets with an LMP pricing regime, the Consortium contends that this point is not accurate.

Despite administering LMP pricing regimes, make-whole payments are needed to ensure appropriate financial compensation in accordance with dispatch instructions that may at times be 'out-of-merit'. In NYISO make-whole payments to generators were approximately $38 million ($US) in 2017[38] and in ISO-NE make-whole payments to generators were approximately $52 million ($US) in 2017[39]. Therefore, make-whole payments are proving to not be 'infrequent and immaterial'.

The Consortium agrees with the IESO decision that "it will provide make-whole payments for dispatch-up and dispatch-down instructions for energy and OR". Make-whole payments will likely be very important and needed considering the operational needs in the northern zones supported by points made earlier in this submission.

Concluding Comments

Overall, the draft SSM HLD is a good document providing clear high-level direction to implement an LMP pricing regime within the IAM. However, the planned move to an LMP pricing regime must address specific pricing and operational issues within the IAM and applicable contract amendments in accordance with forthcoming amendments to the IESO Market Rules.

Principles for price fidelity within the IAM should be established to help guide detailed design decisions, rules, and protocols to be determined within the forthcoming Energy Workstream detailed design consultations towards ensuring that market clearing prices accurately and effectively reflect supply/demand conditions including scarcity.

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[38] See https://www.potomaceconomics.com/wp-content/uploads/2018/06/NYISO-2017-SOM-Report-5-07-2018_final.pdf, specifically 'guarantee payments' to generators which are make-whole payments – NYISO has two different make-whole payments: (i) Bid Product Cost Guarantee (BPCG); and, (ii) Day-Ahead Margin Assurance Payments (DAMAP) (see https://www.nyiso.com/public/markets_operations/documents/tariffviewer/index.jsp and https://www.pjm.com/-/media/committees-groups/task-forces/emustf/20141113/20141113-item-02-uplift-in-the-nyiso-market.ashx for BPCG and DAMAP calculations)

[39] See https://www.potomaceconomics.com/wp-content/uploads/2018/06/ISO-NE-2017-EMM-SOM-Report_6-17-2018_Final.pdf, specifically 'uplift charges' paid to generators which are make-whole payments specifically referred to as Net Commitment Period Compensation (NCPC) payments, where calculations for NCPC payments are listed in ISO-NE's Market Rule 1, Section III, Appendix F (see https://www.iso-ne.com/static-assets/documents/regulatory/tariff/sect_3/mr1_append_f.pdf)

Negative market clearing prices in the northwest zone requires priority attention within the Energy Workstream detailed design consultations. Make-whole payments should also be prioritized within the Energy Workstream detailed design consultations, which is further needed in consideration of potential negative wholesale energy pricing issues.

Market power mitigation design, rules, and protocols must be transparent and sufficient recourse must be afforded to MPs in the event of disagreements with the IESO's application of market power mitigation.

Finally, the Consortium encourages the IESO to develop a Roadmap/Workplan to evolve the IAM beyond the MRP design components and plans within the present Energy and Capacity Workstreams. This Roadmap/Workplan should include design components relating to valuing environmental attributes and potential for new electricity products (e.g., ramping, etc.). In the U.S., a Wind Solar Alliance has recently been formed to create recommendations to evolve the design and rules of select U.S. wholesale electricity markets regarding improvements to pricing energy and scheduling/dispatching resources. The Wind Solar Alliance's recommendations will be captured within a forthcoming white paper aiming to 'leveling the playing field', considering the rapidly changing resource mix driven mainly resulting from increasing uptake variable generators[40].

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

Sincerely,

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[40] See https://windsolaralliance.org/ and https://www.forbes.com/sites/dipkabhambhani/2018/10/09/solar-and-wind-industries-unite-to-rewrite-electric-market-rules-want-fair-market-not-subsidies/#6f3c5f3f351d

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Appendix A – List of Consortium Member Facilities and Projects in Ontario

Organization/Company Name	Facility Name	Project Status	Connection Status	Registered IESO Market Participant?	Fuel Type	Nameplate Capacity (MW)	IESO Contract Type
Algonquin Power & Utilities Corp (Windlectric Inc.)	Amherst Island Wind Project	In Commercial Operation	Transmission	Yes	Wind	74.1	FIT
Algonquin Power & Utilities Corp (Windlectric Inc.)	Effisolar Cornwall Solar Farm A	In Commercial Operation	Distribution	No	Solar	10	FIT
Algonquin Power & Utilities Corp (Windlectric Inc.)	Long Sault Rapids	In Commercial Operation	Transmission	Yes	Hydro	18	NUG PPA
Axium Infrastructure Inc.	K2 Wind Facility	In Commercial Operation	Transmission	Yes	Wind	270	FIT
Axium Infrastructure Inc.	Merherstburg Solar	In Commercial Operation	Distribution	No	Solar	10	FIT
Axium Infrastructure Inc.	Belmont Solar	In Commercial Operation	Distribution	No	Solar	20	FIT
Axium Infrastructure Inc.	Walpole Solar	In Commercial Operation	Distribution	No	Solar	20	FIT
Axium Infrastructure Inc.	Axium Discovery Light Solar	In Commercial Operation	Distribution	No	Solar	10	FIT
Axium Infrastructure Inc.	Axium Foto Light Solar	In Commercial Operation	Distribution	No	Solar	10	FIT
Axium Infrastructure Inc.	Axium City Light Solar	In Commercial Operation	Distribution	No	Solar	10	FIT
Axium Infrastructure Inc.	Kapuskasing Solar Facility	In Commercial Operation	Distribution	No	Solar	7	FIT
Axium Infrastructure Inc.	Ramore Solar Facility	In Commercial Operation	Distribution	No	Solar	8	FIT

Axium Infrastructure Inc.	Mattawishkwia Solar Facility	In Commercial Operation	Distribution	No	Solar	10	FIT
Axium Infrastructure Inc.	Wainwright Solar Facility	In Commercial Operation	Distribution	No	Solar	10	FIT
Axium Infrastructure Inc.	Elmsley East Solar Facility	In Commercial Operation	Distribution	No	Solar	10	RESOP
Axium Infrastructure Inc.	Elmsley West Solar Facility	In Commercial Operation	Distribution	No	Solar	10	RESOP
Axium Infrastructure Inc.	St. Isidore A Solar Facility	In Commercial Operation	Distribution	No	Solar	10	RESOP
Axium Infrastructure Inc.	St. Isidore B Solar Facility	In Commercial Operation	Distribution	No	Solar	10	RESOP
Axium Infrastructure Inc.	Brockville 1 Solar Facility	In Commercial Operation	Distribution	No	Solar	10	FIT
Axium Infrastructure Inc.	Brockville 2 Solar Facility	In Commercial Operation	Distribution	No	Solar	9	FIT
Axium Infrastructure Inc.	Burritts Rapids Solar Facility	In Commercial Operation	Distribution	No	Solar	7	FIT
Axium Infrastructure Inc.	Liskeard 1 Solar Facility	In Commercial Operation	Transmission	Yes	Solar	10	FIT
Axium Infrastructure Inc.	Liskeard 3 Solar Facility	In Commercial Operation	Transmission	Yes	Solar	10	FIT
Axium Infrastructure Inc.	Liskeard 4 Solar Facility	In Commercial Operation	Transmission	Yes	Solar	10	FIT

Axium Infrastructure Inc.	Mississippi Mills Solar Facility	In Commercial Operation	Distribution	No	Solar	10	FIT
Axium Infrastructure Inc.	Wiliam Rutley Solar Facility	In Commercial Operation	Distribution	No	Solar	10	FIT
Axium Infrastructure Inc.	Adelaide 1 Solar Facility	In Commercial Operation	Distribution	No	Solar	10	FIT
Axium Infrastructure Inc.	Ingersoll 1 Solar Facility	In Commercial Operation	Distribution	No	Solar	9.5	FIT
Axium Infrastructure Inc.	Breen 2 Solar Facility	In Commercial Operation	Distribution	No	Solar	10	FIT
Axium Infrastructure Inc.	Midhurst 2 Solar Facility	In Commercial Operation	Distribution	No	Solar	3.5	FIT
Axium Infrastructure Inc.	Midhurst 3 Solar Facility	In Commercial Operation	Distribution	No	Solar	3.5	FIT
Axium Infrastructure Inc.	Midhurst 4 Solar Facility	In Commercial Operation	Distribution	No	Solar	6.5	FIT
Axium Infrastructure Inc.	Midhurst 6 Solar Facility	In Commercial Operation	Distribution	No	Solar	8.5	FIT
Axium Infrastructure Inc.	Orillia 1 Solar Facility	In Commercial Operation	Distribution	No	Solar	10	FIT
Axium Infrastructure Inc.	Orillia 2 Solar Facility	In Commercial Operation	Distribution	No	Solar	10	FIT
Axium Infrastructure Inc.	Orillia 3 Solar Facility	In Commercial Operation	Distribution	No	Solar	6.5	FIT
BluEarth Renewables	Bow Lake CGS	In Commercial Operation	Transmission	Yes	Wind	58.32	FIT

Brookfield Renewable	Andrews GS	In Commercial Operation	Transmission	No	Hydro	47	HCI
Brookfield Renewable	Aubrey Falls GS	In Commercial Operation	Transmission	No	Hydro	162	HCI
Brookfield Renewable	Cameron Falls GS	In Commercial Operation	Distribution	No	Hydro	4	N/A
Brookfield Renewable	Carmichael Falls	In Commercial Operation	Distribution	No	Hydro	20	N/A
Brookfield Renewable	Clergue GS	In Commercial Operation	Transmission	Yes	Hydro	52	HCI
Brookfield Renewable	Comber East - C24Z Wind Project	In Commercial Operation	Transmission	Yes	Wind	82.8	FIT
Brookfield Renewable	Comber West - C23Z Wind Project	In Commercial Operation	Transmission	Yes	Wind	82.8	FIT
Brookfield Renewable	Dunford GS	In Commercial Operation	Transmission	Yes	Hydro	45	HCI
Brookfield Renewable	Gartshore GS	In Commercial Operation	Transmission	Yes	Hydro	23	HCI
Brookfield Renewable	Gosfield Wind	In Commercial Operation	Transmission	Yes	Wind	50.6	RES III
Brookfield Renewable	Harris GS	In Commercial Operation	Transmission	Yes	Hydro	12	HCI
Brookfield Renewable	Hogg GS	In Commercial Operation	Transmission	Yes	Hydro	18	HCI
Brookfield Renewable	Hollingsworth GS	In Commercial Operation	Transmission	Yes	Hydro	23	HCI
Brookfield Renewable	MacKay GS	In Commercial Operation	Transmission	Yes	Hydro	62	HCI
Brookfield Renewable	McPhail GS	In Commercial Operation	Transmission	Yes	Hydro	13	HCI
Brookfield Renewable	Mission Falls GS	In Commercial Operation	Transmission	Yes	Hydro	16	HCI
Brookfield Renewable	Prince I Wind Project	In Commercial Operation	Transmission	Yes	Wind	99	RES I
Brookfield Renewable	Prince II Wind Project	In Commercial Operation	Transmission	Yes	Wind	90	RES II
Brookfield Renewable	Rayner GS	In Commercial Operation	Transmission	Yes	Hydro	46	HCI
Brookfield Renewable	Red Rock Falls GS	In Commercial Operation	Transmission	Yes	Hydro	41	HCI
Brookfield Renewable	Scott Falls GS	In Commercial Operation	Transmission	Yes	Hydro	22	HCI
Brookfield Renewable	Serpent River	In Commercial Operation	Distribution	No	Hydro	7	N/A

Brookfield Renewable	Shekak River	In Commercial Operation	Distribution	No	Hydro	19	N/A
Brookfield Renewable	Steephill Falls GS	In Commercial Operation	Transmission	Yes	Hydro	16	HCI
Brookfield Renewable	Valerie Falls	In Commercial Operation	Distribution	No	Hydro	10	N/A
Brookfield Renewable	Wells GS	In Commercial Operation	Transmission	Yes	Hydro	239	HCI
Boralex Inc.	Port Ryerse Wind Farm	In Commercial Operation	Distribution	No	Wind	10	FIT
Boralex Inc.	West Lincoln Wind Farm	In Commercial Operation	Transmission	Yes	Wind	230	FIT
Boralex Inc.	Swanton Line Wind Farm	In Commercial Operation	Distribution	No	Wind	10	Advanced RESOP
Boralex Inc.	Bisnett Wind Farm	In Commercial Operation	Distribution	No	Wind	10	Advanced RESOP
Boralex Inc.	Marsh Line Wind Farm	In Commercial Operation	Distribution	No	Wind	10	Advanced RESOP
Boralex Inc.	Front Line Wind Farm	In Commercial Operation	Distribution	No	Wind	10	Advanced RESOP
Boralex Inc.	Richardson Wind Farm	In Commercial Operation	Distribution	No	Wind	10	Advanced RESOP
Boralex Inc.	Gracey Wind Farm	In Commercial Operation	Distribution	No	Wind	10	Advanced RESOP
Boralex Inc.	Naylor Wind Farm	In Commercial Operation	Distribution	No	Wind	10	Advanced RESOP
Boralex Inc.	North Malden Wind Farm	In Commercial Operation	Distribution	No	Wind	10	Advanced RESOP

Boralex Inc.	South Side Wind Farm	In Commercial Operation	Distribution	No	Wind	10	Advanced RESOP
Capstone Infrastructure	Erie Shores Wind Farm	In Commercial Operation	Transmission	Yes	Wind	99	RES 1
Capstone Infrastructure	Goulais Wind Farm	In Commercial Operation	Transmission	Yes	Wind	25	FIT
Capstone Infrastructure	Sky Generation	In Commercial Operation	Distribution	Yes	Wind	5.1	RESOP
Capstone Infrastructure	Ravenswood	In Commercial Operation	Distribution	Yes	Wind	9.9	RESOP
Capstone Infrastructure	Proof Line	In Commercial Operation	Distribution	Yes	Wind	6.6	RESOP
Capstone Infrastructure	Skyway 8	In Commercial Operation	Distribution	Yes	Wind	9.48	RESOP
Capstone Infrastructure	GH ZEP	In Commercial Operation	Distribution	Yes	Wind	10	FIT
Capstone Infrastructure	GH Clean	In Commercial Operation	Distribution	Yes	Wind	18.45	FIT
Capstone Infrastructure	Ganaraska	In Commercial Operation	Distribution	Yes	Wind	17.6	FIT
Capstone Infrastructure	Snowy Ridge	In Commercial Operation	Distribution	Yes	Wind	10	FIT
Capstone Infrastructure	Settlers Landing	In Commercial Operation	Distribution	Yes	Wind	8	FIT
Capstone Infrastructure	Amherstburg Solar	In Commercial Operation	Distribution	Yes	Solar	20	RESOP
Cordelio Power Inc	Jericho Wind Energy Centre	In Commercial Operation	Transmission	Yes	Wind	150	FIT
Cordelio Power Inc	Bluewater Wind Energy Centre (Blake)	In Commercial Operation	Transmission	Yes	Wind	60	FIT
Cordelio Power Inc	Summerhaven Wind Energy Centre	In Commercial Operation	Transmission	Yes	Wind	125	FIT
Cordelio Power Inc	Conestogo Wind Energy Centre	In Commercial Operation	Distribution	No	Wind	23	FIT
Cordelio Power Inc	Moore Solar Project	In Commercial Operation	Distribution	No	Solar	20	RESOP

Cordelio Power Inc	Sombra Solar Project	In Commercial Operation	Distribution	No	Solar	20	RESOP
EDF Renewables Canada Inc	Romney Wind Energy Centre	Under Development	Transmission	No	Wind	59.95	LRP I
EDF Renewables Canada Inc	Pendleton Solar Energy Centre	Under Development	Distribution	No	Solar	19.83	LRP I
EDF Renewables Canada Inc	Barlow Solar Energy Centre	Under Development	Distribution	No	Solar	18.18	LRP I
EDF Renewables Canada Inc	Arnprior Solar Project	In Commercial Operation	Distribution	Yes	Solar	23.4	RESOP
EDP Renewables	South Branch Wind Farm	In Commercial Operation	Distribution	No	Wind	30	FIT
EDP Renewables	Nation Rise Wind	Under Development	Transmission	Yes	Wind	100	LRP I
Enbridge Inc.	Talbot Wind Farm LP	In Commercial Operation	Transmission	Yes	Wind	98.9	RES III
Enbridge Inc.	Greenwich Wind Farm LP	In Commercial Operation	Transmission	Yes	Wind	98.9	RES III
Enbridge Inc.	Underwood WGS	In Commercial Operation	Transmission	Yes	Wind	181.5	RES II
ENGIE Canada Inc.	Erieau Wind LP	In Commercial Operation	Transmission	Yes	Wind	99	FIT
ENGIE Canada Inc.	East Lake St. Clair Wind LP	In Commercial Operation	Transmission	Yes	Wind	99	FIT

ENGIE Canada Inc.	Pointe-Aux-Roches Wind LP	In Commercial Operation	Transmission	Yes	Wind	48.6	FIT
ENGIE Canada Inc.	Plateau I & II (Plateau Wind Inc.)	In Commercial Operation	Distribution	No	Wind	18	FIT
ENGIE Canada Inc.	Plateau III (Plateau Wind Inc.)	In Commercial Operation	Distribution	No	Wind	9	FIT
ENGIE Canada Inc.	Mohawk Point Wind Farm (AIM SOP Phase 1 LP)	In Commercial Operation	Distribution	No	Wind	9.9	RESOP
ENGIE Canada Inc.	Cultus Wind Farm (AIM SOP Phase I LP)	In Commercial Operation	Distribution	No	Wind	9.9	RESOP
ENGIE Canada Inc.	Clear Creek II Wind Farm (AIM SOP Phase I LP)	In Commercial Operation	Distribution	No	Wind	9.9	RESOP
ENGIE Canada Inc.	Frogmore Wind Farm (AIM SOP Phase I LP)	In Commercial Operation	Distribution	No	Wind	9.9	RESOP
ENGIE Canada Inc.	Harrow I (AIM Harrow Wind Farm LP)	In Commercial Operation	Distribution	No	Wind	9.9	RESOP
ENGIE Canada Inc.	Harrow II (AIM Harrow Wind Farm LP)	In Commercial Operation	Distribution	No	Wind	9.9	RESOP

ENGIE Canada Inc.	Harrow III (AIM Harrow Wind Farm LP)	In Commercial Operation	Distribution	No	Wind	9.9	RESOP
ENGIE Canada Inc.	Harrow IV (AIM Harrow Wind Farm LP)	In Commercial Operation	Distribution	No	Wind	9.9	RESOP
ENGIE Canada Inc.	Brockville Solar Inc.	In Commercial Operation	Distribution	No	Solar	10	FIT
ENGIE Canada Inc.	Beckwith Solar Inc.	In Commercial Operation	Distribution	No	Solar	10	FIT
H2O Power Holding LP	Island Falls GS	In Commercial Operation	Transmission	Yes	Hydro	44	HCI
H2O Power Holding LP	Iroquois Falls GS	In Commercial Operation	Transmission	Yes	Hydro	30	HCI
H2O Power Holding LP	Twin Falls GS	In Commercial Operation	Transmission	Yes	Hydro	27.5	HCI
H2O Power Holding LP	Calm Lake GS	In Commercial Operation	Transmission	Yes	Hydro	9.5	HCI
H2O Power Holding LP	Sturgeon Falls GS	In Commercial Operation	Transmission	Yes	Hydro	8.4	HCI
H2O Power Holding LP	Fort Frances GS	In Commercial Operation	Transmission	Yes	Hydro	12.3	HCI
H2O Power Holding LP	Kenora GS	In Commercial Operation	Transmission	Yes	Hydro	6	HCI
H2O Power Holding LP	Norman GS	In Commercial Operation	Transmission	Yes	Hydro	12.5	HCI
Innergex Renewable Energy	Umbata Falls Hydroelectric Project	In Commercial Operation	Transmission	Yes	Hydro	25	RES I
Innergex Renewable Energy	Glen Miller Hydroelectric Project	In Commercial Operation	Distribution	Yes	Hydro	8	RES I
Innergex Renewable Energy	Batawa	In Commercial Operation	Distribution	No	Hydro	5	N/A
Innergex Renewable Energy	SP1	In Commercial Operation	Distribution	No	Solar	10	RESOP
Innergex Renewable Energy	SP2	In Commercial Operation	Distribution	No	Solar	7	RESOP
Innergex Renewable Energy	SP3	In Commercial Operation	Distribution	No	Solar	10	RESOP

Kruger Energy Inc.	Kruger Energy Port Alma LP	In Commercial Operation	Transmission	Yes	Wind	101.2	RES II
Kruger Energy Inc.	Kruger Energy Chatham LP	In Commercial Operation	Transmission	Yes	Wind	99.4	RES III
NextEra Energy Canada, LP	Adelaide Wind Energy Centre	In Commercial Operation	Transmission	Yes	Wind	59.9	FIT
NextEra Energy Canada, LP	Bornish Wind Energy Centre	In Commercial Operation	Transmission	Yes	Wind	72.9	FIT
NextEra Energy Canada, LP	Goshen Wind Energy Centre	In Commercial Operation	Transmission	Yes	Wind	102	FIT
NextEra Energy Canada, LP	Cedar Point II Wind Energy Centre	In Commercial Operation	Transmission	Yes	Wind	100	FIT
NextEra Energy Canada, LP	East Durham Wind Energy Centre	In Commercial Operation	Distribution	Yes	Wind	22.2	FIT
Pattern Energy	Armow Wind Project	In Commercial Operation	Transmission	Yes	Wind	180	GEIA
Pattern Energy	Belle River Wind	In Commercial Operation	Transmission	Yes	Wind	99.82	GEIA
Pattern Energy	Grand Renewable Energy Park	In Commercial Operation	Transmission	Yes	Wind	148.6	GEIA
Pattern Energy	South Kent Wind Project	In Commercial Operation	Transmission	Yes	Wind	270	GEIA
Suncor Energy Inc.	Adelaide Wind Power Project	In Commercial Operation	Transmission	Yes	Wind	39.978	FIT
wpd	Springwood Wind Farm	In Commercial Operation	Distribution	No	Wind	8.2	FIT

wpd	Whittington Wind Farm	In Commercial Operation	Distribution	No	Wind	6.15	FIT
wpd	Sumac Ridge Wind Farm	In Commercial Operation	Distribution	Yes	Wind	10.25	FIT
wpd	Napier Wind Farm	In Commercial Operation	Distribution	No	Wind	4.1	FIT

Appendix B – IESO MPWG Issues List (April 5, 2007)

Most issues below directly impact market clearing prices while a few issues do not (e.g., Historical Analysis of Nodal Prices, Publishing Nodal Price Data).

Some of the issues below have been partially addressd (e.g., 12-times Ramp Rate, Peak Demand Load Forecast in Pre-Dispatch) while others have not.

The list below includes the Issues ID number that was assigned by the IESO for purposes of tracking issues within the MPWG.

- 001 – Pre-Dispatch Price Uncertainty
- 002 – Publishing Nodal Price Data
- 003 – Information to Explain Dispatch Optimization Process
- 004 – Use of 12-times Ramp Rate in the Dispatch Unconstrained Algorithm
- 005 – Simultaneous Use of Ramping Generation Units for Energy and Operating Reserve
- 006 – Effects of Emergency Purchases on the Market
- 007 – Imports and Exports Setting Price
- 008 – Systematic Differences Between Day-Ahead and Real-Time Markets
- 009 – Use of Peak Demand Load Forecast in Pre-Dispatch
- 010 – Over-Forecasting of Demand in Hours 23, 24
- 011 – Comparing Treatment of Self-Scheduling Resources in Pre-Dispatch and Real-Time
- 012 – Under-Commitment of Available Generation
- 013 – Impact of Out of Market Sources of Operating Reserve on the Market
- 014 – Hour(s)-Ahead Price Signal Uncertainty
- 015 – Restriction on Changes to Dispatch Data between 4 and 2 hours ahead of Dispatch Hour
- 016 – Historical Analysis of Nodal Prices
- 017 – Settlement Adjustment and Allocation
- 018 – Pricing and Allocating Line Losses
- 019 – Penalty Factors
- 020 – Treatment of Imports in a Congestion Pricing Regime
- 021 – *incorporated into Issue #027*
- 022 – Pricing Physical Constraints
- 023 – Uncertainty with respect to Constraint Payments
- 024 – Reducing Frequency of Failed Intertie Transactions
- 025 – Temporal Optimization in the Real-Time Constrained Sequence but Not in the Real-Time Unconstrained Sequence
- 026 – Integration of Competitive and Regulated Wholesale Prices
- 027 – Timing Differences Between Unconstrained And Constrained Real-Time Sequences
- 028 – Compensation under Administered Pricing when Incorrect Prices have been Posted

- 029 – *incorporated into Issue #001*
- 030 – Forecast of Real-Time Price
- 031 – Multi-Interval Optimization Pricing Methodology
- 032 – Role of Import Offer Guarantee
- 033 – Rules for Determining Prices in Times of Shortage
- 034 – Rules Concerning the Breaker Status of “Quick Start Facilities”
- 035 – Impact of “Other” Out Of Market Control Actions on the Market
- 036 – Pricing In-Market Control Action Operating Reserve
- 037 – Operating Reserve Initiatives

Appendix C – Present Challenges within ISO-NE Capacity Market

Exelon's Request to De-List Generating Units at Mystic Generation Facility

In March 2018, Exelon announced that it filed with ISO-NE to retire Mystic generating station's units 7, 8, 9, and the Jet unit on June 1, 2022 (totaling 2000 MW), and that absent any regulatory reforms to properly value reliability and regional fuel security, the units would not participate in the Forward Capacity Auction (FCA) scheduled for early 2019. In the announcement, Exelon noted the importance of changes to ISO-NE's market rules that could address resiliency considering the reliability risks identified in ISO-NE's January 2018 fuel security report. Importantly, Exelon stated that these market rules changes are needed because critical units in the region cannot recover future operating costs, including costs to secure fuel.[41]

Following the announcement, ISO-NE issued a memorandum to stakeholders, stating that the retirement of these units would pose "an unacceptable fuel security risk to the region during the winter months."[42] ISO-NE sought a tariff waiver from the FERC in May 2018 for an out-of-market remedy (i.e., reliability must-run contract), in the form of a cost-of-service agreement with Exelon to keep units 8 and 9 operating to ensure fuel security in 2022 and beyond.[43] ISO-NE recognized that its Tariff permits the ISO to retain retiring resources to resolve transmission security issues, but does not provide for cost-of-service agreements to address reliability risks related to fuel security. The FERC denied ISO-NE's request and required ISO-NE to make improvements to its market rules to address fuel security concerns and to issue a short-term cost recovery proposal for the units.[44] On July 13, 2018, FERC issued an order establishing hearing procedures to determine Exelon's cost-of-service compensation that Exelon filed on May 16.[45] ISO-NE filed a short-term proposal at the end of August 2018. ISO-NE is planning on treating resources retained for fuel security as price-takers in the next FCA, meaning that Mystic's capacity will be offered into the FCA for the 2022-23 period at a price of zero, ensuring they clear the market.[46] ISO-NE will be filing long-term market rule changes by July 1, 2019 that will create a market-based mechanism to address fuel security risks.[47]

[41] http://www.exeloncorp.com/newsroom/exelon-generation-files-to-retire-mystic-generating-station-in-2022

[42] https://d12v9rtnomnebu.cloudfront.net/library-page/4-3_Memo_Immediate_and_NearTerm_Fuel_Security.pdf

[43] https://www.iso-ne.com/static-assets/documents/2018/05/iso_petition_for_waiver_of_tariff_provisions.pdf

[44] https://www.ferc.gov/CalendarFiles/20180702193957-ER18-1509-000.pdf

[45] http://isonewswire.com/updates/2018/7/31/update-on-iso-nes-operational-fuel-security-initiatives.html

[46] https://www.spglobal.com/platts/en/market-insights/latest-news/electric-power/073018-generators-say-mystic-order-mirrors-their-capacity-price-concerns

[47] http://isonewswire.com/updates/2018/7/31/update-on-iso-nes-operational-fuel-security-initiatives.html

Invenergy's New England Gas-Fired Generation Project

On September 20, 2018, ISO-NE submitted a resource termination filing with FERC for Invenergy's Clear River Unit 1.[48] The filing is the culmination of issues that Invenergy has faced in developing their project. Clear River Unit 1 is a proposed combined-cycle gas-fired generation project located in Rhode Island. The project obtained a capacity supply obligation for only one turbine unit for the tenth FCA that was held in February 2016 for the 2019-2020 commitment period. The second unit of the project failed to clear in the tenth (2016) and eleventh (2017) FCAs and was disqualified from participating in the twelfth FCA (2018) due to a failure to demonstrate to ISO-NE that Invenergy was making progress in meeting project milestones. Specifically, the basis for disqualification was significant delays and lack of progress in obtaining the necessary permits. Invenergy has not yet received many major permits including: no agreement with National Grid for its transmission interconnection; no Rhode Island Energy Facility Siting Board permit for the interconnection; and, no air or wetlands permits.[49] Delays have also come from opposition to the facility's water plan.[50] The original commercial operation date for the plant was to be no later than the start of the commitment period (June 1, 2019).

Invenergy has transferred its obligations to another supplier (i.e., 'covering' its obligation) for both the 2019-2020 and the 2020-2021 commitment periods due to delays in project development. Under ISO-NE's market rules, if a project sponsor covers its obligation for two commitment periods, then ISO-NE can terminate the obligation.

In addition, Invenergy has made little progress to begin construction of the project since 2016, according to critical path schedule reports. Delays have caused the commercial operation date to be later than June 1, 2021. Under its market rules, ISO-NE can also terminate an obligation if the date by which a resource will have achieved all of its critical path schedule millstones is more than two years beyond the beginning of the commitment period for which the resource first received an obligation. Since Invenergy has not only covered its obligation for two commitment periods, but also because the commercial operation date is more than two years beyond the commitment period for which the plant first received an obligation, ISO-NE filed to terminate the project's obligation for the 2021-2022 commitment period. ISO-NE requested that FERC issue an Order within 60 days.[51]

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[48] https://www.iso-ne.com/static-assets/documents/2018/09/clear_river_1_involuntary_res_term.pdf

[49] https://upriseri.com/wp-content/uploads/2018/09/Supplemental-Testimony-of-Walker-Sept-2018-clean-3.pdf

[50] http://www.providencejournal.com/news/20171101/power-grid-operator-disqualifies-proposed-burrillville-plant-from-electricity-auction

[51] https://www.iso-ne.com/static-assets/documents/2018/09/clear_river_1_involuntary_res_term.pdf