IESO Response to Feedback on the Day-Ahead Market Calculation Engine Detailed Design Document

Below are the IESO's responses to stakeholder feedback on the Day-Ahead Market (DAM) Calculation Engine detailed design document.

ID	Stakeholder	Feedback	IESO Response
N/A	Multiple	Multiple stakeholders asked for examples, scenarios, and walkthroughs of the detailed design.	The IESO has been working with stakeholders collaboratively through the Detailed Design discussion, to further the understanding of stakeholders, and provide background, clarification, and rationale where needed. Further, the IESO has focused on providing background and examples to stakeholders, both in writing and in various stakeholder forums, that answer specific requests. The IESO and stakeholders recognize that the transition to a renewed market can bring forward many requests for scenarios or examples on the impacts on participants, and the IESO will aim to respond to these requests that provide the greater value to the broad stakeholder community, and provide the greatest efficacy. Stakeholders are also encouraged to engage resources to provide them strategic advice on to navigate the nuances of their participation in the renewed market.
619	AMPCO	Many areas of the document provide information on intermediary values that explain how or why a resource was dispatched or priced in a particular manner. For example, each of the pricing runs would seem to output a set of shadow prices for each of the possible constraints in the run. The IESO should elaborate on whether these types of outputs would be helpful for participants, or even IESO staff (if only accessible internally) in understanding dispatch or pricing outcomes. AMPCO continues to encourage the IESO to consider informational requirements that will help participant understand complex market outcomes.	In addition to providing schedules and prices from the final pass of the day-ahead market, the IESO will also provide the shadow prices for binding constraints that are used to generate locational marginal prices. The list of such shadow prices are found in Table 3-30. The IESO will publish this information within five business days after the trade date. This information will assist stakeholders in understanding the constraints that affect locational prices in the day-ahead market. Further details will need to be established during the implementation phase with input from market participants where practical. The IESO will not publish results of intermediate steps within Pass 1 and 2 of the DAM calculation engine. The IESO is concerned that publishing the results from the intermediate steps of the DAM calculation engine may provide opportunities for inappropriate conduct, such as the exercise of market power. The IESO encourages all market participants to offer their resources based on their short-run marginal cost (including opportunity costs) to promote competition and overall market efficiency.
620	AMPCO	[...] we would like the IESO to walk stakeholders through examples of [constraint penalty violation] curves, particularly the various OR violation curves. This has an important impact on price and we would like to fully understand this prior to the finalization of the Detailed Design phase.	The materials presented at the Constraint Violations stakeholder engagement meeting on November 25, 2019 describe the interrelationship of the operating reserve penalty curves and include supporting graphs and illustrations. The curve quantities and prices presented in the materials are used for illustrative purposes only. The actual values that will be used for the future market will be determined during the development of market rules and market manuals.

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621	AMPCO	[...] we are confused by the treatment of DL no bid with respect to demand forecast in the various passes of the DAM engine. It appears from section 3.9.1.3. that DL without a bid, or bidding Maximum Market Clearing Price (MMCP) in its entirety, is only considered as demand in the reliability pass (Pass 2), and we wonder how their consumption will be accounted for in Passes 1 and 3. The document is silent on this and it needs to be clarified.	The non-dispatchable load forecast for Passes 1 and 3 will not account for dispatchable load resources that do not submit a bid. The DAM calculation engine utilizes bids from dispatchable load resources to form dispatchable load schedules in Passes 1 and 3. Therefore dispatchable load resources without a bid will be scheduled to zero in these two passes. This will be clarified in Version 2 of the DAM detailed design document.
623	AMPCO	As part of the stakeholder engagement, the IESO proposed a settlement floor of -$20/MWh, whereas the detailed design document for the DAM specifies -$100/MWh. AMPCO comments provided at the time of the technical sessions signalled our discomfort with a settlement floor of any kind, without the consideration of a settlement ceiling. Despite stakeholder comments, we did not see any response on the stakeholder pages as to how the IESO has taken these comments into consideration, or why the -$100/MWh value was settled on. AMPCO requests that the IESO provide additional rationale and engagement for this change.	The IESO hosted a technical session on the topic, and received advice from stakeholders, as noted. Upon receiving that advice, the IESO re-reviewed the challenge, where fundamentally, these market outcomes of very low negative price occurring would be to the detriment of Ontario ratepayers, with no broad market benefit. The IESO looked at alternatives to this solution, including the potential to introduce an offer floor price for hydro. However, the complexities surrounding water management make creating an offer price floor a difficult task that could also have adverse effects on system reliability. Given these considerations the IESO decided instead to pursue the proposed concept. The request to consider a settlement ceiling was assessed, however, there is not an equivalent market inefficiency due to similar conditions that requires resolution on the positive price side.
644	Electricity Distributors Association	We repeat that, in addition to identifying the required amendments to IESO Market Rules and Market Manuals, the IESO, the Ontario Energy Board (OEB), and the Ministry of Energy, Northern Development and Mines (MENDM) should proactively engage with LDCs and their customers to identify, scope, evaluate and decide on enabling legislative amendments, amendments to regulatory policy and regulatory instruments. For example, it remains unclear how LDCs will be invoiced under MRP and how their customers' bills will change as a result. We continue to assume that the OEB will amend the applicable formulas used to calculate the Regulated Price Plan (RPP) price to account for new wholesale market prices. We also assume that the OEB will amend the formulas used in the Retail Settlement Code and replace references to the Hourly Ontario Energy Price (HOEP) with the appropriate new wholesale market price. Doing so will clarify how the electricity commodity charges for non-RPP customers, whose electricity commodity charges currently consist of the HOEP and Global Adjustment charges, are to be quantified in the reformed market. These clarifications are essential for our LDC members that will be responsible for implementing revised or possibly new settlement and billing processes, and who will be the main point of contact for communications with electricity customers with respect to changes on electricity bills. The IESO's published materials to-date have not provided instruction as to which wholesale market price produced in the renewed market will apply to non-RPP customers.	The IESO will continue to work closely with stakeholders, including the Local Distribution Company (LDC) community, throughout the Detailed Design, and Implementation phases to work to address these issues as proactively as possible, and will take this advice under advisement.

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645	Electricity Distributors Association	[...] each Detailed Design produced by the IESO should consistently apply terminology and defined terms. For example, within the Day-Ahead Market (DAM) Calculation Detailed Design, the IESO uses the following terms interchangeably: • "DAM Hourly Ontario Zonal Prices" • "prices for the Ontario zone" • "Ontario Zonal price". [...] the IESO should use standardized terms (e.g.,DAM Ontario Zonal Price) correctly and consistently so that confusion is avoided, the usability of the documents is improved and gap analysis is facilitated.	Thank you for the feedback. The IESO will amend V2.0 of the document to consistently use that naming convention.
646	Electricity Distributors Association	[...] We believe that the IESO DAM Calculation Engine would be improved by adding a clear summary of the inputs required for NDL settlement and clear instruction for the calculation and reporting of these inputs.	For details on how non-dispatchable loads are settled, please refer to Section 3.6.3 of the Market Settlement detailed design document. Section 3.8.3 of the DAM Calculation Engine detailed design document provides the calculation engine outputs that will be utilized for settlement of non-dispatchable loads.
647	Electricity Distributors Association	[...] A mapping of the outputs of the DAM Calculation Engine to the IESO's market settlement processes and ultimately to market participants settlement processes will improve the Summary.	Please refer to Section 3.8.3 for a description of the outputs from the DAM calculation engine that will be utilized for settlement.
649	Electricity Distributors Association	We are concerned that the Detailed Design does not reference changes proposed by the interim design of the IESO's Storage Design Project. We characterize the Detailed Design as being incomplete as a result. For example, the IESO does not include references to 'electricity storage participants' per MR-00445-R00-R05 ('Implementation of the Interim Storage Design'). However, MR-00445-R00-R05 is currently being reviewed by the IESO's Technical Panel in preparation for consideration by the IESO's Board of Directors, the final step in the Market Rule amendment process.	Market Renewal is aware of the proposed changes identified by the Energy Storage Design Project (ESDP) interim design and will incorporate the changes into the draft MRP market rules and market manuals once the ESDP interim design rules are live.
650	Electricity Distributors Association	We note that in several instances, the Detailed Design states: "... the DAM calculation engine will record all such values for information purposes". We seek IESO clarification with respect to whether this information will be recorded and reported publicly. We observe that information such as this will be useful to market participants, including LDCs, for investment decisions (e.g., in generation or non-wires alternative technologies and locations) and other purposes.	The IESO will publish public reports containing the shadow prices described in DAM Pricing, Section 3.8.2.7, outputs. This information can help market participants assess binding transmission limits that contribute to locational prices in the day-ahead market. The additional reports will be described in V2.0 of the Publishing and Reporting detailed design document. The intermediate information produced from Passes 1 and 2 of the day-ahead market calculation engine do not provide similar benefits and will not be made public.

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651	Electricity Distributors Association	Section 3.2 Objectives The IESO notes that nodal and zonal prices will provide more accurate pricing signals and improve incentives for market participants to submit offers at marginal costs. We seek confirmation that the IESO considered the unique characteristics of the Ontario electricity sector (e.g., contracted resources, rate-regulated resources, Global Adjustment cost allocation) in this Detailed Design. As demonstrated elsewhere in this submission (refer to Section 3.10 below), reforms to the wholesale market must consider the interplay of out-of-market payments to generators and the implications for consumers who respond to price signals that recover such out-of-market costs.	As the IESO moves ahead with Market Renewal, we are taking into account the unique characteristics of the province, and will proceed by working closely with stakeholders. One of the goals of Market Renewal is to improve the clarity and transparency of price signals within the wholesale market. There are no plans to move out-of-market costs to be recovered by a different method in the renewed market, but we will work with stakeholders through the Implementation phase to show the rules and manuals that will govern settlement.
652	Electricity Distributors Association	Section 3.4.1.2 Load Inputs The IESO proposes that bids associated with aggregated HDR resources will be identified using a 'proxy bus' which depends only on the aggregated resources zonal location. We repeat our concern set out in our July 31, 2020 comments on the Market Settlements Detailed Design that the computation of the LFDC requires that the DAM_QSW be quantified for all N-PRL HDR resources at a specific delivery point. We seek this clarity as a proxy bus is generic, and is not specific to a delivery point, which would appear to compromise the accuracy of the LFDC.	The IESO will continue to model aggregated hourly demand resources at a proxy bus within each zone. This level of detail will provide adequate information to market participants. More granular modelling of Hourly Demand Response (HDR) location would require system and process enhancements that will not be undertaken as part of Market Renewal.
653	Electricity Distributors Association	Section 3.6.1.2 Variables and Objective Function In this section, the IESO defines "quantity scheduled from hourly demand response (SHDR)" as the amount of HDR reductions scheduled at the bus for each hour. For aggregated HDR resources within an IESO zone, the IESO should clarify whether SHDR would be associated with a 'proxy bus' or the actual bus. This clarification is reasonable as the SHDR is used in the derivation of DAM_QSW for all N-PRL HDR resources.	As is the practice today, aggregated hourly demand response resources will be modeled at a proxy bus within each electrical zone. The variable Scheduled Hourly Demand Response (SHDR) will therefore be associated with a proxy bus for aggregated hourly demand response resources.
654	Electricity Distributors Association	Section 3.8.3 Outputs for Energy and OR Settlement The IESO defines BHDR_NOT_PRL as the set of buses identifying N-PRL HDR resources. We seek clarification whether BHDR_NOT_PRL includes 'proxy buses' for HDR resources consisting of aggregated contributors. This clarification is reasonable as this value is required for the derivation of the DAM_QSW for all N-PRL HDR resources. We question whether Table 3-32 should be re-labelled, specifically to replace "Forecast Deviation per MW Charge" with "Load Forecast Deviation Charge (LFDC)". Table 3-32 defines "Quantity bid by Hourly Demand Response (QHDR)-SHDR" as the amount of consumption scheduled at a bus associated with a N-PRL HDR resource. In addition, we seek to confirm whether QHDR-SHDR is the same as the DAM_QSW for N-PRL HDR resources per the Market Settlement Detailed Design.	The IESO can confirm that the set BHDR_NOT_PRL will contain aggregated hourly demand resources. As proposed, the IESO will update the label for Table 3-32 from "Forecast Deviation per MW Charge" to "Load Forecast Deviation Charge (LFDC)" The DAM calculation engine output of QHDR-SHDR values, which is the amount of consumption scheduled for each hourly demand response resource, will be utilized by settlements as DAM_QSW for all hourly demand response resources.

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655	Electricity Distributors Association	Section 3.9.1.3 Network Model The IESO states that: • load distribution factors (LDFs) "define the load pattern that will be used to distribute the IESO demand forecast for each demand forecast area" • LDFs "will be also used to determine a set of weighting factors to distribute the net virtual transactions scheduled at each virtual transaction trading zone." • the weighting factors are used to "renormalize the LDFs as per the load facilities mapped to each virtual transaction trading zone to determine the weighting factors for each trading zone". We seek improved clarity (e.g., worked examples) of the derivation of renormalized LDFs and of how renormalized LDFs are used in subsequent calculations. This clarification is reasonable since LDFs will be used in the derivation of the DAM_QSW for NDLs.	Re-normalized load distribution factors are utilized for virtual transactions. They are not utilized for non-dispatchable load settlement.
656	Electricity Distributors Association	Section 3.10 Pricing Formulas The IESO proposes an energy settlement floor price of -$100/MWh and describes that prices not in the range established by the minimum market clearing price and the settlement price floor, will be modified (i.e., adjusted to the settlement floor price). The IESO also proposes that generators be able to submit bids as low as -$2000/MWh. We seek additional information from the IESO on the impacts of adjusting prices and the IESO's policies on adjusted prices, including: • how often does IESO anticipate the need to adjust or modify prices? • which locations in the province are anticipated to be impacted by the modification of prices to the settlement floor? • when prices are modified, will IESO publish the un-modified price? • what are the impacts of modifying prices on consumers? We are concerned that Class A and Class B customers will experience different outcomes when prices are adjusted. We wish to understand the IESO's analysis of the trade-offs between these customer groups when setting its policy on determining settlement price floors. Consider the scenario where a lower settlement price floor results in lower LMPs which would increase the Global Adjustment. Class A customers will benefit from the lower price and Class B customers will see both the lower commodity price and a higher Global Adjustment.	In its stakeholder engagement material from November 2017, the IESO presented analysis regarding the frequency of negative prices in each of Ontario's electrical zones. That analysis showed that the frequency of locational prices that were substantially negative was less than 0.1% of intervals in Southern Ontario, roughly 2% of intervals in Northeastern Ontario and approximately 10% of intervals in the Northwestern region of the province. The information can be found on slide 44 at the following link: Single-Schedule Market Load Pricing. The IESO will publish energy prices that are within the settlement bounds of +$2,000/MWh to -$100/MWh. Prices that are outside of the settlement bounds will not be published. Not modifying substantially negative prices would significantly depress locational prices in regions where oversupply is most common; such as Northwestern Ontario. Very low locational prices could mean that exports in the northwest would be paid up to $2,000/MWh to purchase power from Ontario. The suppliers of that power would be largely shielded from the -$2,000/MWh energy price by the terms of their contract or regulated rate. The net effect would be a depressed local energy price, increased profits to exporters, a higher global adjustment, and subsequently, higher costs to Ontario ratepayers.

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657	Electricity Distributors Association	Section 3.10.1.3 Zonal Energy Prices The IESO describes that the "ZonalP" (or the DAM Ontario Zonal Price) will be calculated as the sum of: • the hourly reference price • load distribution-weighted loss component within the Ontario zone • the load distribution-weighted congestion component within the Ontario zone. We seek clarification as to which components of the DAM Ontario Zonal Price will be recorded and published and at what level of granularity (e.g., at the bus).	The IESO will publish the individual Locational Marginal Price (LMP) and its components (reference price, loss component, congestion component) of all load resources that are a constituent of the DAM Ontario Zonal Price. The LMPs will be determined at the delivery point of each load resource.
658	Electricity Distributors Association	Section 3.13 Determination of the Non-Dispatchable Load Forecast [...] We urge the IESO to provide more details on the different aspects of forecasting, including its consideration of forecast accuracy given increased uptake of distributed energy resources (DERs). Upon review of this Detailed Design, it is not apparent to us at what point the IESO determines the DAM_QSW for NDLs, a significant quantity to be used when settling with NDLs. We therefore seek clarification from the IESO and suggest that the Detailed Design be amended to set out how this quantity is derived.	The enduring documentation that will be used to provide greater detail about the IESO's future near-term area demand forecast methodology will be shared with stakeholders during the implementation phase. The IESO also acknowledges the importance of accounting for distributed energy resources (DERs) in its area demand forecasts. Exploring new data sets to provide greater DER visibility is planned as part of solution development and testing. Schedules for every delivery point of non-dispatchable load resources (DAM_QSW for non-dispatchable load) will be calculated by distributing the demand forecast using load distribution factors as described in Section 3.9.1.
642	OEA	[...] A major concern is the mathematic formulae included in the detailed design may not be comprehended by market participants that do not have advanced mathematic knowledge (include the writer of the submission in this group). What means is the IESO undertaking to ensure all market participants are confident the formulae included in all the calculation engines (DAM, PD and RT) meet the intended design? OEA members recommend an independent third party review and report as a minimum requirement.	During implementation the IESO will be engaging with a 3rd party to review the functionality of the Day-Ahead, Pre-Dispatch and Real-time calculation engines. The review will provide assurance that the functionality of each calculation engine is consistent with the intended design as documented in the market rules.
660	OPG	As a means of providing additional clarity the IESO should add a short (i.e. one or two sentence) explanation of the function and purpose for all the equations presented in the design.	The IESO has endeavored to provide descriptions for each equations in the document. The descriptions are intended to enhance the clarity of each equation's function.

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661	OPG	OPG would like clarification on the requirements for self-scheduling resources to participate in the DAM. Section 3.3 of Offers, Bids & Data Inputs draft detailed design includes the following statement, which implies that self-scheduling resources need to participate in the DAM: "Registered market participants must submit dispatch data into the day-ahead market for the amount of energy they reasonably expect their self-scheduling generation facility, intermittent generator or transitional scheduling generator to provide in each dispatch hour of the real-time market;" However, Section 3.3.1. of the draft Grid & Market Operations Detailed Design states that self-scheduling resources are not subject to the ADE requirement and Section 4, Table 4-1 (page 122) includes the following statement: "There is no requirement for dispatch data to be submitted into the day-ahead market in order for a self-scheduling generation facility, an intermittent generator, a transitional scheduling generator or a boundary entity to be eligible to participate in the real-time market." The IESO should clarify the participation requirements for self-scheduling resources in the DAM and RTM. Are self-scheduling resources required to submit dispatch data in the DAM and if they do not, can they still participate in the real-time market?	The design does not change the obligations for self-scheduler participation in the IESO-administered markets. Self-schedulers will continue to have an obligation to provide their forecasted production and associated offer price in the day-ahead timeframe. The Availability Declaration Envelope does not, and will not, restrict self-schedulers from participating in the real-time market.

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662	OPG	[...] Without enhancements to joint-optimization, there is a high risk that hydroelectric resources will receive OR schedules in the DAM that they will not be able to physically achieve in real-time. Without enhanced joint optimization of energy and OR, infeasible day-ahead OR schedules create inefficient market outcomes. [...] OPG noted in the July 8th, 2020 meeting between IESO and the Ontario Waterpower Association (OWA), the IESO alluded to changes to the calculation engines that may reduce or mitigate this concern. [...]. However, it is not clear how the equations in the DA calculation engine design address this issue and the newly introduced Max DEL constraint equations reduce the efficiency, competitiveness, and transparency for hydroelectric resources in both energy and OR markets. The IESO should continue stakeholder discussions to address the significant challenges being created under the Market Renewal Program for hydroelectric. [...] OPG is currently participating in stakeholder sessions with the IESO related to "Improving Accessibility of Operating Reserve". OPG has raised this proposed parameter with the IESO Stakeholder Engagement team, and they suggested the parameter be raised again through Market Renewal, as this additional tool change would be out of scope for their project. Through this stakeholder engagement the IESO has amended their ORA Performance Criteria to track actual dispatch rather than scheduled dispatch when issuing OR Activations (ORAs) in order for participants to meet their ORAs and be able to utilize their compliance deadband fully, this change would require changes to the DSO. OPG firmly believes this "Energy plus OR Limit" parameter should be addressed through Market Renewal or other active Market Initiatives, such as Expanding Participation in Operating Reserve and Energy (EPOR-E) or Improving Accessibility of OR.	The request for an additional parameter for energy plus operating reserve cannot be accommodated for a number of reasons. Firstly, aligning with the intent of the Market Renewal design process, there is no impact from the design that creates a material change, or an increased risk, to this limited scenario in the future market. Secondly, there are a set of mitigating actions available to market participants in today's market that can continue to be used in the future market to reduce this risk of this type of described event from occurring. Thirdly, the calculation engines do not have the capability to evaluate additional constraints beyond those already accommodated for the co-optimization of energy and reserve.
663	OPG	OPG would like confirmation that the nodes used for LMP in the new market will be at the same location on the grid as the resource locations in the current market.	Yes, this is confirmed.

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664	OPG	On page 32 just below Table 3-12 the design states: "In circumstances where there is a conflict between the dispatch data parameter values submitted by a registered market participant for a hydroelectric facility, the engine would likely be unable to produce a solution. In such situations, the DAM calculation engine will be permitted to violate conflicting constraints created by the dispatch data submitted, as required." If the DA engine needs to violate these constraints, the IESO should provide a set order in which the constraints will be softened/violated. For example, if Hourly Must Run and Minimum Hourly Output conflict, the engine should violate the Minimum Hourly Output and not the Hourly Must Run. The order of constraint violations should be similar in day ahead, pre-dispatch and real-time to enable the calculation engines to consistently model physical operating constraints that become safety, equipment limitations, and applicable law (SEAL) restrictions in real-time. This approach should allow the IESO to resolve potential conflicts well in advance of real-time. In OPG's comments provided for Offers Bids & Data Inputs Detailed Design, OPG identified limitations of the IESO detailed design which currently does not allow hydroelectric resources to use the hydroelectric parameters in the DAM, as the hydroelectric parameters are defined for SEAL constraints only. OPG recommended alternate wording to enable the use of hydroelectric parameters similar to how non quick start (NQS) units have physical operating constraints like minimum loading (MLP) and minimum generation block running time (MGBRT). OPG reiterates that hydroelectric stations have physical operating constraints in day ahead, but do not always have SEAL concerns until closer to real-time. Enabling the use of hydroelectric parameters to model physical operating constraints in day ahead and pre-dispatch will allow the parameters to aid in the creation of more feasible day-ahead and pre-dispatch schedules for hydroelectric and produce more efficient, competitive outcomes for market participants.	For constraints that are in conflict, the calculation engine may be permitted to relax the constraint in order to produce a solution. The sequence by which constraints will be relaxed will be developed by the IESO in collaboration with hydroelectric participants during implementation. This sequence will be the same in each timeframe. Constraints related to safety, equipment or applicable law (SEAL) such as Hourly Must Run (HMR) will not be relaxed. Therefore, Minimum Hourly Output will be permitted to be violated before HMR.
665	OPG	The IESO should provide details on how the tie-breaking modifiers for each variable generator will be determined (i.e. the TMBb value). Will the values be the same in the day ahead and real-time markets and how often will they change (e.g. monthly, daily, hourly)?	There will be no change to this process in the future market. Tie-breaking modifiers for variable generation resources are determined via the daily dispatch order. The IESO currently randomly determines this daily dispatch order for variable generators that are registered market participants, and regularly updates and publishes such daily dispatch order in accordance with the applicable market manual.
666	OPG	As per previous comments submitted by OPG on the high level design, OPG remains concerned over the decision to adopt dynamic loss factors given the challenges that arose when they were first implemented at market opening in 2002. See OPG's previous comments on the Single Schedule Market high level design regarding dynamic loss factors [...].	Loss factors will be fixed during the dispatch hour. This should alleviate many of the challenges of using dynamic loss factors at market opening. For details, please refer to Section 3.7 of the Real-Time Calculation Engine detailed design document.

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667	OPG	How will notification of reliability must-run and reactive support obligations be communicated to market participants in the new market? In the current market, these instructions are provided in real-time. Will the IESO also be communicating these instructions day-ahead as well?	There will be no change to how notifications of reliability must-run and reactive support obligations are provided to market participants. They will continue to be provided when the IESO identifies their need. For example, if a system condition is identified for the next day which requires a reliability must-run resource, the IESO will notify the market participant in the day-ahead timeframe and input reliability constraints for the resource in the DAM.
668	OPG	Multiple sections of the design note that testing for economic withholding is not performed on energy offers below $25/MWh and physical withholding testing is not performed when the LMP is less than $25/MWh. A review of NYISO and MISO thresholds indicates they use $25USD/MWh. The IESO should convert this figure to Canadian dollars which is approximately $35 CAD/MWh. This would be appropriate as the IESO has indicated that many of these thresholds are based on US jurisdictional review. Further this value should be reviewed by the IESO on a periodic basis (e.g. every three years) to ensure it remains relevant for the Ontario market and reflects current gas prices, technology, etc.	The $25/MWh threshold is a measure of materiality that is consistent with US jurisdictions. This value is also aligned with historical price data from Ontario. The IESO will continually observe the performance of the Market Power Mitigation framework following Market Renewal go-live. Any alterations required to better ensure it is supporting efficient market outcomes will be made through the Market Rule amendment process.
669	OPG	[...] For market transparency, the Constraint Area Designations used as DAM calculation inputs should be published in advance of the DAM submission window closing: this would allow market participants to react to upcoming market conditions.	The IESO will post Narrow Constrained Area and Dynamic Constrained Area designations in advance of the day-ahead market and ahead of pre-dispatch scheduling for the day-at-hand. This detail is reflected in Section 3.12.5 of the Market Power Mitigation detailed design document. Other constrained areas (Broad Constrained Area, global) are outcomes of market scheduling and are not known in advance.

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670	OPG	Setting reference level prices for hydroelectric will be challenging given the relationship between opportunity costs, available water, and the configuration of the units at a resource. Physical offer quantities for hydroelectric resources also rely on available head/flows, which are dynamic in nature. Determination of these reference prices and quantities need to be thoroughly consulted and agreed upon with market participants. OPG would also like to highlight the risks associated with fuel supply (water) that a hydroelectric market participant has in the day-ahead timeframe and urges the IESO to factor risk premiums and dynamic opportunity costs into reference levels. (Note: changes to inflows also impact head based capacity of hydroelectric stations). Hydroelectric resources can be energy limited and offers are used to reflect the opportunity cost of water in what is expected to be the most valuable hours. If these offers fail the conduct and impact test, the ex-ante engine automatically overrides the market participant's offers with reference prices. This could result in a sub-optimal dispatch schedule as reference prices may not accurately represent the opportunity cost of the water, as these costs are dynamic and change hourly. This may also have operational implications on the market participant, leading to sub-optimal market outcomes and may invoke SEAL declarations.	The IESO has proposed a methodology to account for opportunity cost in energy reference levels for energy-limited resources. The details related to this methodology were provided as pre-reading to the August 27, 2020 stakeholder engagement session: Reference Levels and Quantities. We have since received your feedback on this topic, and continue to engage with stakeholders on this challenging topic. We look forward to continuing the discussion regarding the methodology for determining opportunity costs in Q4 of 2020.
671	OPG	[...] When the reference bus is out of service, the IESO should publish the alternative station used as the reference bus. The location of the reference bus will impact congestion and loss components impacting market participants.	The reference bus will not be out of service very often. In the rare circumstances when the reference bus is out of service, calculation engines will select another reference bus based on network topology and prevailing system conditions. The LMPs will not change when an alternative reference bus is used. The change in reference bus will change the individual components of LMP but the total LMP will remain the same. When another location is selected as the reference bus, it can be determined by the market participants by examining the components of LMP to identify which location has both loss and congestion component equal to zero.
672	OPG	[...] The IESO should provide an example of each of the violation cost variables listed on pages 54-56, with a focus on Operating Reserve Demand Curves (ORDC) which is a new concept under market renewal.	The materials presented at the Constraint Violations stakeholder engagement meeting on November 25, 2019 describe the interrelationship of the operating reserve penalty curves and include supporting graphs and illustrations. The curve quantities and prices presented in the materials are used for illustrative purposes only. The actual values that will be used for the future market will be determined during the development of market rules and market manuals.

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673	OPG	For market transparency and settlement reconciliation purposes, the IESO should publish in confidential reports the bid/offer constraints applying to single hours.	The IESO will publish the day-ahead market schedules and commitments in confidential reports to the registered market participants for their applicable resources. This information will assist market participants in understanding how their resources were scheduled for the next dispatch day. Additionally, the IESO will provide the shadow prices for binding constraints that are used to generate locational marginal prices. The list of such shadow prices in found in Table 3-30. The IESO will publish this information within five business days after the trade date. This information will assist stakeholders in understanding the constraints that affect locational prices in the day-ahead market. The IESO will not publish reports related to how resource-specific scheduling constraints are applied for individual resources in the DAM calculation engine. The DAM calculation engine will evaluate all resources and their applicable constraints across the multi-hour optimization horizon to make commitment and scheduling decisions. Numerous factors can contribute to scheduling of individual resource. It would not be possible to publish a report that can rationally explain constraints that were applied in a single hour for each resource.
674	OPG	[...] Please provide details of how inadvertent payback transactions are optimized within the DA Calculation Engine and publish the DA schedules for inadvertent transactions.	In the current market, inadvertent payback is accounted for by adding to global demand when Ontario is paying back and subtracting from global demand when Ontario is being paid back. In the future market, inadvertent payback will be modeled as a firm transaction at the appropriate intertie zone to be scheduled by the DAM calculation engine.

ID	Stakeholder	Feedback	IESO Response
676	OPG	In section 3.6.1.5 on Dispatchable Generation the design states: "Energy schedules for each dispatchable generation resource cannot vary by more than an hour's ramping capability for that resource. The following three-part constraint handles ramping for a resource when it is committed. The constraint covers incremental change above the resource's minimum loading point (MLP) in the hours where: the resource first reaches MLP (Start Up), the resource stays on at or above MLP (Continued On), and the last hour the resource is scheduled at or above MLP before being scheduled off (Shut Down). Only the "Continued On" constraint applies to quick-start resources because they are always committed." Please provide an example of how this constraint is applied to a non-quick start unit and for market transparency publish the constraints in confidential reports.	In Section 3.6.1.5, the energy ramping constraints for dispatchable generation resources account for the resource ramping profile. These constraints ensure that the submitted ramp rates are satisfied for all time intervals. When a Non-Quick Start (NQS) resource is committed, it is assumed that the resource is at its minimum loading point at the beginning of the first commitment hour and at the end of the hour before shut down. Therefore, the schedule, which applies to the mid-point of the hour, cannot exceed minimum loading point (MLP) plus 30-minutes of ramp up capability with respect to the first commitment hour, and MLP plus 30-minutes of ramp-down capability with respect to the hour before shut down. All hours in between are scheduled with respect to 60-minutes of ramp up and down capability between adjacent hours. The IESO will publish the day-ahead market schedules and commitments in confidential reports to the registered market participants for their applicable resources. This information will assist the market participants to understand how their resources were scheduled for the next dispatch day. Additionally, the IESO will provide the shadow prices for binding constraints that are used to generate locational marginal prices. The list of such shadow prices in found in Table 3-30. The IESO will publish this information within five business days after the trade date. This information will assist stakeholders in understanding the constraints that affect locational prices in the day-ahead market. The IESO will not publish reports related to how scheduling constraints are applied for individual resources in the DAM calculation engine. The DAM calculation engine will evaluate all resources and their applicable constraints across the multi-hour optimization horizon to make commitment and scheduling decisions. Numerous factors can contribute to scheduling of individual resources. It would not be possible to publish a report that can rationally explain constraints that were applied in a single hour for each resource.
677	OPG	[...] Please provide examples of how the constraints for Minimum Generation Block Running Time (MGBRT) and Minimum Loading Point (MLP) from the previous day schedule are applied and how this impacts settlement of DA Generator Offer Guarantee and DA Make Whole Payments. The IESO should also clarify which schedule from the previous day is used for the initial input to the day ahead.	Initial schedules for the DAM will be based on the hour ending 24 schedules of the most recent pre-dispatch run.
678	OPG	OPG cautions the IESO to ensure the calculation engine's ability to perform mitigation testing does not negatively impact the ability to optimize day-ahead and pre-dispatch schedules in a timely fashion. The running time of the mitigation module should not cause the IESO to abandon hydroelectric optimization parameters or other market efficiencies. If this becomes the case, the IESO should re-assess the thresholds and re-open negotiations on reference levels.	The DAM calculation engine will run in the time period between 10:00 EPT and 13:30 EPT and can be extended to 15:30 EPT on an exception basis in the event of issues causing delayed results. This time period is believed to be sufficient for executing all the features and steps of the DAM calculation engine design, including market power mitigation and optimization considering all new hydroelectric parameters.

ID	Stakeholder	Feedback	IESO Response
679	OPG	[...] Please provide an example of how the conduct test is applied, for the case where a resource is selected for two conduct tests in both energy and operating reserve. It is unclear of how the most stringent thresholds will be applied. This example should explain how this impacts Reference Level Scheduling, Reference Level Pricing and the Market Power Mitigation Price Impact Test.	If in a given hour of the day-ahead market a resource meets the conditions for testing conduct within both a Narrow Constrained Area (NCA) and a Broad Constrained Area (BCA) the conduct test for the energy offer will use the NCA threshold when comparing the energy reference level to the submitted energy offer. If in that same hour, the same resource also met the condition for testing conduct for Operating Reserve (OR) the conduct test for OR offers will use the OR local market power thresholds to compare the OR reference level to the submitted OR offer. If the price impact test was failed for energy, but not for operating reserve, the energy offer would be replaced with the energy reference level. Since the OR price impact test was not failed, no mitigation would be applied to the OR offer.
680	OPG	[...] If the IESO is imposing a settlement floor price of -$100/MWh, it should be appropriately stakeholdered with market participants. Please provide the rationale for this new amount and the reason for the change from -$20. [...] The IESO should seek to quantify the benefits of the proposed change to the settlement floor and determine whether this change will require an additional mechanism to correct inefficient and inappropriate settlements. For example: Will this result in an additional make whole payment? In summary OPG would like to discuss the quantum of the Settlement Floor in order to ensure there are limited inefficient market outcomes and inappropriate settlement amounts.	The IESO hosted a technical session on the topic, and received advice from stakeholders, as noted. Upon receiving that advice, the IESO re-reviewed the challenge, where fundamentally, these market outcomes of very low negative price occurring would be to the detriment of Ontario ratepayers, with no broad market benefit. The IESO looked at alternatives to this solution, including the potential to introduce an offer floor price for hydro. However, the complexities surrounding water management make creating an offer price floor a difficult task that could also have adverse effects on system reliability. Given these considerations the IESO decided instead to pursue the proposed concept.
681	OPG	Per equation on Page 61 for determination of 10S OR schedule, the IESO should confirm whether a condensing or speed-no-load (SNL) quick-start unit is prevented from receiving a 10S schedule. [...] If IESO confirms the current implementation prevents a SNL/Condensing quick start unit from receiving a 10S schedule, OPG encourages the IESO to resolve this condition. [...] An example of the application of the above equation for synchronized 10-minute operating reserve for a dispatchable generator would be beneficial to provide additional clarity.	This constraint will not limit 10S scheduling for a quick-start resource. A quick-start resource will always be considered as 'committed' in each hour when it has been offered because such resources do not have commitment costs and have an MLP of zero.

ID	Stakeholder	Feedback	IESO Response
682	OPG	The constraint equations to prevent hydroelectric resources from being scheduled within a forbidden region (at the bottom of page 63 and top of page 64) only appear to include terms for scheduled energy. IESO should consider the need for an additional constraint that prevents scheduled energy plus scheduled OR from landing in a forbidden region. If the combined DA schedules for energy and OR fall within a forbidden region, then subsequent OR activation may be infeasible. In the current market, the IESO sends ORAs within a forbidden region which may cause market participants to generate above the ORA to ensure the activation is deemed successful. The IESO should remedy this existing deficiency in market design.	The IESO has considered this suggestion and can provide the following information. In the event an OR activation occurs in real-time (OR activations do not occur in the day-ahead market) the real-time calculation engine will respect the submitted forbidden region of the resource. The resource will therefore be dispatched to a higher MW quantity in consideration of the upper limit of the forbidden region.
683	OPG	On page 67 the design states: "Energy-limited resources cannot be scheduled to provide more energy than they have indicated they are capable of providing. In addition to limiting energy schedules over the course of the day to the energy limit specified for a resource, the corresponding constraints ensure that energy-limited resources cannot be scheduled to provide energy in amounts that would preclude them from providing operating reserve when activated." The IESO should provide an example for a hydroelectric station with the following attributes: Min DEL = 400 MWh Max DEL = 500 MWh Hourly Energy Capacity = 100 MW Hourly Operating Reserve Capacity = 80 MW The example should aim to answer the following questions, for current market and future market: 1. How many MWh of OR can be scheduled in a day? 2. How many MWh of Energy + OR can be scheduled in a day? OPG notes that in today's market, the ability to provide OR is assessed on an hourly basis and is independent of the DEL calculation. If OR is activated (ORA) then future energy for the day or next day would be reduced to meet any safety, equipment, or applicable law requirements at the station. The IESO should provide rationale including analysis about benefit to the market that is achieved by changing the calculation of DEL to include OR.	These maximum daily energy limit (Max DEL) constraints are identical to those used in today's day-ahead calculation engine. They ensure that in any given hour, an ORA activation would not cause a violation on the resource's Max DEL. There are 24 Max DEL constraints for each resource. For example, in HE8, the Max DEL constraint will ensure that the sum of energy scheduled from HE1 to HE8, plus the OR scheduled in HE8, is less than or equal to the resource's Max DEL. Similarly, for HE24 the Max DEL constraint will ensure that the sum of energy scheduled from HE1 to HE24, plus the OR scheduled in HE24, is less than or equal to the resource's Max DEL.

ID	Stakeholder	Feedback	IESO Response
685	OPG	Section 3.6.1.6 on page 70 the design states: "Injections and withdrawals at each bus must be multiplied by one plus the marginal loss factor to reflect the losses or reduction in losses that result when injections or withdrawals occur at locations other than the reference bus. These loss-adjusted injections and withdrawals must then be equal to each other, after taking into account the adjustment for any discrepancy between total and marginal losses. Load or generation reduction associated with the demand constraint violation will be subtracted from the total load or generation to ensure that the DAM calculation engine will always produce a solution." The IESO should provide an example to illustrate how this will impact transactions scheduled on the interties. Today's penalty losses published by the IESO for intertie export transactions for NY.ROSETON, MI.LUDINGTON, MD.CAVERTCLIFF can be less than 1.0 and lower than the penalty losses published for internal Ontario generation. OPG is concerned this is not an efficient and competitive approach that should be continued under MRP.	The IESO agrees that using dynamic loss factors produces more efficient results than does using static loss factors. The new calculation engines will calculate and use dynamic loss factors to achieve more efficient scheduling and dispatch of both internal resources and intertie transactions. As per definition of loss penalty factors, if an incremental injection at a resource location (internal supplier or intertie location) would increase losses inside Ontario, its loss penalty factor would be greater than 1. If it reduces losses within Ontario, then its loss penalty factor would be less than 1.
688	OPG	[...] The IESO should publish the results for both As-Offered Scheduling and Pricing, this will provide market transparency into market power mitigation actions and are required for settlement reconciliation.	In addition to providing schedules and prices from the final pass of the day-ahead market, the IESO will also provide the shadow prices for binding constraints that are used to generate locational marginal prices. The list of such shadow prices are found in Table 3-30. The IESO will publish this information within five business days after the trade date. This information will assist stakeholders in understanding the constraints that affect locational prices in the day-ahead market. Further details will need to be established during the implementation phase with input from market participants, where practical. The IESO will not publish results of intermediate steps within Pass 1 and 2 of the DAM calculation engine. The IESO is concerned that publishing the results from the intermediate steps of the DAM calculation engine may provide opportunities for inappropriate conduct, such as the exercise of market power. The IESO encourages all market participants to offer their resources based on their short-run marginal cost (including opportunity costs) to promote competition and overall market efficiency.

ID	Stakeholder	Feedback	IESO Response
690	OPG	[...] Please provide examples to clarify when an ELR with binding DEL is eligible to set price. It is unclear how OR schedules impact Daily Energy Limit and why OR schedules would impact the ability to set price. OPG requests clarification of the following scenarios: 1. Hourly As-Offered Energy Schedule of 50 MW and OR schedule 10 MW, how is price set? 2. If later passes of the DAM result in 60 MW Energy and 0 MW OR, how is price set? 3. If later passes of the DAM result in 60 MW Energy and 10 MW OR, how is price set? 4. An example where the binding As-Offered Schedule is not at the economic operating point (EOP) of either energy or OR. How is price setting eligibility determined? 5. How does the price setting eligibility impact the calculation of price considering the joint optimization of energy and OR?	LMPs are determined by the resource that is available to supply an additional MW of demand. When an energy limited resource (ELR) has a maximum daily energy limit (DEL) that is binding it is not able to provide additional MWs in response to incremental demand. Therefore, they will not set LMPs in the day-ahead market. This information was provided to stakeholders in the calculation engine and price setting eligibility technical session held on August 27, 2020.
691	OPG	Please elaborate on the intent and mechanics of the following DEL equation [...] Is this equation intended to examine all laminations of a single bus, or does it place a constraint on dispatchable generation scheduled at all ELR buses ($SDGh,b,k$) against the total across all ELR AND hydroelectric resources ($SDGh,b,kAOS$)?	The constraints described in the equation are applicable to a single bus. They are required to ensure the eligibility of an offer or bid lamination to set price is appropriately reflected in the pricing steps of the DAM calculation engine when the Max DEL constraint of an energy-limited resource is binding in the respective scheduling step.
692	OPG	[...] OPG suggests that [min DEL price-setting eligibility] requires further review and consideration depending on whether the resource was scheduled at or above its economic operating point. If the resource was scheduled at or above its economic operating point, it should be eligible to set price regardless of a binding Min DEL at some point over the 24 hour day.	When the resource has a binding minimum daily energy limit (Min DEL), those MW that were optimally scheduled by the DAM calculation engine to satisfy the Min DEL constraint will not be eligible to set prices. Resources will be eligible to set price for the available MW above the Min DEL constraint.
694	OPG	The IESO should provide additional explanations on how the locational marginal prices (LMPs) calculated in the new market will differ from the shadow prices calculated in today's market? An example of the difference between LMP and shadow prices would add context. A specific example using net interchange scheduling limit and potential for make whole payments is also suggested. For additional transparency, shadow prices should be published in Day Ahead, Pre-dispatch, and Real-time as this will aid decision making of market participants.	The main difference between the future LMPs and today's nodal prices for energy (commonly referred to as shadow prices) determined by the constrained schedule of pre-dispatch and real-time is that the future LMPs will be used for settlement. This means that the LMPs will be determined using the constraint violation prices for pricing and the LMP and its components will be capped at the maximum and minimum settlement prices; +$2,000/MWh and -$100/MWh respectively. The IESO will publishing LMPs and their components (reference price, loss and congestion components) in the day-ahead, pre-dispatch and real-time timeframes. The IESO will also provide the shadow prices for binding constraints that are used to generate locational marginal prices. The list of such shadow prices in found in Table 3-30. This information will assist stakeholders in understanding the constraints that affect locational prices in the renewed markets.

ID	Stakeholder	Feedback	IESO Response
696	OPG	[...] From [Section 3.6.4.3], it appears the IESO plans to test all the dispatch data parameters (energy offer, start-up offer, and speed no-load offer) even though only one parameter qualified for testing. Please provide clarification of this approach, as it does not appear to be consistent with the MPM detailed design document.	When a resource qualifies to be tested for market power mitigation, all relevant dispatch data parameters will be subject to the conduct test. For example, when a resource's congestion component is >$25/MWh, the IESO will test the energy offer, speed-no-load offer and start-up offer (as applicable) for conduct. This is described in Section 3.6.1.2 of the Market Power Mitigation detailed design document.
700	OPG	[...] The IESO should provide the outputs [of the price impact test] to market participants as confidential reports to inform market participants of mitigation events and to allow for settlement reconciliation. Please provide examples of the revised set of offer data that must be output by the price impact test. This process was hard to follow without illustrative examples.	As described in the Publishing and Reporting detailed design document, the IESO will inform market participants when their resource has failed the price impact test for energy or operating reserve.
705	OPG	In section 3.7.1.2, the design states: "Thus, Reliability Scheduling will maximize the value of the following expression: $\Sigma(ObjDLh - ObjHDRh + ObjXLh - ObjNDGh - ObjDGh - ObjIGh - TBh - ViolCosth)$…" followed by definitions of each term. Please provide a non-mathematically expressed definition of this expression and each of the terms. It is very difficult for market participants to review these equations completely without advance degrees in math.	The objective function of Reliability Scheduling is to minimize the incremental commitment costs associated with meeting the forecast peak demand for all hours of the next day. This is accomplished by maximizing the sum of the following quantities over all 24 hours of the trade day: The value of: • Scheduled dispatchable load energy; less the offered costs of • Scheduled operating reserve (10-minute synchronized, 10-minute non-synchronized, and 30-minute) from dispatchable load; Less the offered costs of: • Scheduled hourly demand response energy reduction; Plus the value of: • Scheduled export energy; less the offered costs of • Scheduled operating reserve (10-minute non-synchronized and 30-minute) from exports; Less the offered costs of: • Scheduled non-dispatchable generation resource energy; • Scheduled dispatchable generation resource energy; less the offered costs of • Scheduled operating reserve (10-minute synchronized, 10-minute non-synchronized, and 30-minute) from dispatchable generation facilities; and • Scheduled hourly import energy; less the offered costs of • Scheduled operating reserve (10-minute non-synchronized and 30-minute) from imports; Less the cost of: • Violating constraints The purpose of the TB term is to achieve a prorated result in the event of a tie between bid/offer laminations.

ID	Stakeholder	Feedback	IESO Response
706	OPG	In section 3.7.1.3 the design states: "For energy-limited resources or hydroelectric resources with a shared maximum daily energy limit, the schedule for each offer lamination must be equal to the schedules corresponding to the Pass 1 scheduled and unscheduled portions. …The schedules for the Pass 1 scheduled and unscheduled portions of the lamination must respect the affiliated quantities." Please clarify what is meant by the "affiliated quantities". Are the "affiliated quantities" at the resource level or at the shared daily energy limit level?	An affiliated quantity is the scheduling variable corresponding to a specific bid/offer lamination. The affiliated quantity is at the resource level and is not a reference to shared Max DEL. For the purpose of implementing the ELR treatment in Pass 2 for ELR resources that have a binding Max DEL constraint in Pass 1, each offer lamination will be split into two parts, Q1DG and Q2DG, corresponding to the scheduled and unscheduled quantities of the lamination in Pass 1. In Pass 2 the calculation engine will schedule these laminations which are denoted respectively as variables S1DG and S2DG. These schedule variables, S1DG and S2DG, therefore must be respectively less than Q1DG and Q2DG, their corresponding offer laminations ("affiliated quantities")
707	OPG	Please explain how $AdjMaxDGh,b$, is considered an Operating Reserve constraint since it only appears to be revised due to variable generation changes.	Thank you for pointing this out. As variable generation (VG) resources are not able to provide operating reserve, the adjustment to AdjMaxDG for VG resources in Pass 2 does not impact any operating reserve constraints. The IESO will update the DAM Calculation Engine detailed design document to reflect this.
711	OPG	[...] What intermediate modifications is the DA calculation engine performing on DAM bid or offer data? Will this intermediate modification be transparent to impacted market participants?	This is referring to ex-ante market power mitigation. The DAM calculation engine may replace DAM offers with reference level offers if a given offer fails the conduct and price impact tests. If an offer is replaced by a reference level the market participant will be notified.

ID	Stakeholder	Feedback	IESO Response
624	Power Advisory	Inputs to Set Prices Require More Clarity and Should Best Reflect Shortage/Scarcity Conditions and Power System Supply Needs [...] IESO should commit to shortage/scarcity pricing in MRP design and rules to accurately value energy and OR. [...] Regarding some of the inputs to set LMPs, more clarity is needed for these components: • More details are required to inform market participants (MPs) and stakeholders on IESO's application of the constraint violation penalty curves – in particular, clear numerical examples on how LMPs will be set when constraint violation penalty curves are applied, and when IESO can relax constraint violation penalty curves so as they will not set LMPs; • [...] the Consortium is still of the opinion that IESO should implement shortage/scarcity pricing for energy and OR within MRP, and consider implementation of an OR Demand Curve (ORDC) and/or some form of Extended LMP (ELMP) where certain variables are relaxed in respective calculation engines to permit non-convex costs (e.g., speed no-load) to be an input towards setting LMPs; and, • IESO inputs relating to OR requirements and securing additional OR, IESO adjustments to centralized forecasts for variable generator (VG) energy production, IESO adjustments to demand forecasts, IESO determination on reliability constraints, and IESO use of emergency control actions, all require more details and examples regarding how IESO interventions could impact resource scheduling and dispatch instructions, as well as setting LMPs. Process details are needed, particularly regarding how IESO makes decisions whether to adjust or activate these inputs. While not a specific comment regarding DAM design, additional to the above points regarding inputs to set LMPs to best ensure prices reflect shortage/scarcity positions, IESO should also revisit the two-hour 'mandatory window' within RTM and explore shortening this window to enable generators to adjust offer data in response to power system conditions. This will also provide more accurate LMPs better reflecting real-time shortage/scarcity conditions. For example, some hydroelectric generators will be better able to efficiently manage water usage for real-time energy production resulting from shortening the RTM mandatory window.	The materials presented at the Constraint Violations stakeholder engagement meeting on November 25, 2019 describe the interrelationship of the operating reserve penalty curves and include supporting graphs and illustrations. The curve quantities and prices presented in the materials are used for illustrative purposes only. The actual values that will be used for the future market will be determined during the development of market rules and market manuals.

ID	Stakeholder	Feedback	IESO Response
625	Power Advisory	Proposed Price Settlement Floor Requires More Analysis and Specific Stakeholder Engagement [...] the 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 settling 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 real-time dispatch. Consequentially to the potential changes to 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 is not contemplated within any of the draft MRP detailed design documents. [...] IESO will need to define tie-breaking rules to determine which supply resources are dispatched and which are curtailed, including treatment of self-scheduling generators and generators with 'must-run' status. This potential outcome has further implications for operations of applicable generation facilities (e.g., water management, etc.) along with contract drivers and settlements relating to contract amendments triggered by MRP related amendments to the IESO Market Rules. [...] The Consortium recommends that IESO conduct further analysis on the potential impacts of implementing a -$100/MWh price settlement floor within MRP detailed design, and consult with MPs and stakeholders due to the following reasons: • Potential to create or exacerbate SBG in some sub-zones – creating issues for dispatch and curtailment; • Provisions and settlements of contracts and regulated framework may financially protect some generators, however IESO may still have operational issues regarding dispatch and curtailment (e.g., exacerbated SBG); and, • 'Must-run' generators may face competition to dispatch and energy production – potentially creating less 'must-run' and production of less energy.	The DAM calculation engine will determine the optimal schedules based on offers and bids to resolve constraints such as energy balance (which can include surplus baseload generation conditions) or transmission limits. In the event the optimization results in a tie between resources, the tie-breaking rules described in section 3.4.1.4 will apply. These tie-breaking rules are also used in the current IESO-administered markets.
626	Power Advisory	Section 3.3 – DAM Calculation Engine Functions The second to last paragraph on p. 16 states that "A … quick-start resource will always be committed in each hour when it has been offered because such resources do not have commitment costs and have an MLP of zero." This statement should be reviewed and specified that the quick-start resource must also be economic so as to 'clear' the DAM for RTM dispatch.	Committed means that the resource will be scheduled to at least its minimum loading point (MLP) and will be eligible for economic scheduling above its MLP. Non-dispatchable or quick-start resources have an MLP of 0 MW and therefore are always considering to be committed and available to be dispatched above MLP. Any schedules above zero will be determined economically by the calculation engine.

ID	Stakeholder	Feedback	IESO Response
627	Power Advisory	Section 3.3 – DAM Calculation Engine Functions The second paragraph on p. 17 refers to the security assessment function. While understandably not discussed in detail during the HLD stakeholder engagement meetings, more details are needed regarding some of the aspects of the security assessment function (e.g., more details on base case power flow and application of operating security limits (OSLs) including how OSLs may change from time-to-time, how contingency analysis will be done by IESO and its impacts, etc.). It is acknowledged that many details are included within Section 3.9 – Security Assessment Function.	Additional information on the security assessment function can be found in Appendix 7.5A of the Market Rules.
628	Power Advisory	Section 3.4.1.2 – Load Inputs Under the Demand Forecasts sub-section on p. 20, as stated under the General Comments section in this submission, more details are needed regarding when and how IESO will adjust demand forecasts.	The methodology to adjust demand forecasts to arrive at a quantity that is representative of load that is considered non-dispatchable - as described in Section 3.13 - will always be performed before the calculation engine uses these forecasts.
629	Power Advisory	Section 3.4.1.3 – Supply Inputs Under the sub-section Hydroelectric Resources within Table 3-10 on p. 30, regarding the Hourly Must-Run, Minimum Hourly Output, and Minimum Daily Energy Limit dispatch data, there are two comments regarding their descriptions. First, operational parameters should be added as a reason for applicable dispatchable hydroelectric generators to use these new dispatch data, and not just for reasons that would endanger safety of any person, damage equipment, or violate an applicable law. Second, more analysis and stakeholder engagement are needed regarding uncoupling offer prices from Hourly Must-Run dispatch data. In general, offer prices should be commensurate with indications and intentions for 'must-run' energy.	Thank you for your feedback. Please see the IESO's responses regarding submission eligibility for the new hydroelectric parameters under the Offers, Bids, and Data Inputs feedback. Uncoupling of offer prices with Hourly Must-Run (HMR) quantities is unnecessary. Offer price restrictions are not required to support HMR submissions since the volume of HMR energy scheduled will not be eligible to set price.
630	Power Advisory	Section 3.4.1.3 – Supply Inputs The second to last paragraph on p. 32 states that "In circumstances where there is a conflict between the dispatch data parameter values submitted by a … hydroelectric facility, the engine would likely be unable to produce a solution … DAM calculation engine will be permitted to violate conflicting constraints by the dispatch data … as required." More details and information are required under what circumstances this can be done to best determine solutions.	For constraints that are in conflict, the calculation engine may be permitted to relax the constraint in order to produce a solution. The sequence by which constraints will be relaxed will be developed by the IESO in collaboration with hydroelectric participants during implementation. This sequence will be the same in each timeframe.
631	Power Advisory	Section 3.4.1.4 – Additional IESO Data Inputs Under the Operating Reserve Requirements sub-section on p. 34, more details are needed regarding how IESO will define the number of regions with specific OR minimum requirements and maximum restrictions.	Minimum area operating reserve requirements will continue to be used to schedule a minimum amount of operating reserve in areas of the IESO-controlled grid. Maximum area operating reserve requirements will continue to be used to prevent over-scheduling of operating reserve in areas of the IESO-controlled grid. These areas will continue to represent locations within the grid where scheduling of operating reserves on resources may be restricted due to constraints on the transmission system.

ID	Stakeholder	Feedback	IESO Response
632	Power Advisory	Section 3.4.1.4 – Additional IESO Data Inputs Under the Resource Minimum and Maximum Constraints sub-section on pp. 36-37, more details are needed regarding how IESO will define reliability constraints, including minimum and maximum constraints.	As described in Section 3.5 of the Offers, Bids and Data Inputs Detailed Design Chapter, reliability constraints may be applied by the IESO to specific registered facilities as scheduling constraints within all calculation engines to support reliability must-run contracts, reactive support service contracts or other reliability needs. The DAM calculation engine will respect these 'must commit' resource constraints by ensuring they are committed in the targeted hours.
634	Power Advisory	Section 3.4.1.4 – Additional IESO Data Inputs [...] the Consortium believes that more analysis and new tie-breaking rules may be required under SBG conditions within the Tie-Breaking sub-section on p. 41.	The IESO does not foresee any new tie-breaking issues under SBG conditions as a result of the renewed market design. The IESO will consult stakeholders if any changes to the tie-breaking rules are required.
635	Power Advisory	Section 3.5.3 – Variable Generation Resource Tie-Breaking The proposed VG tie-breaking rules to determine which VGs will be dispatched to produce energy and which VGs will be economically curtailed appears to be the same formula used in today's IAM (under a regime of uniform prices and Congestion Management Settlement Credits (CMSC) payments). Considering MRP design will implement LMPs and eliminate CMSC payments, IESO should consider extrapolating this formula at least on a zonal basis.	There is no proposed change to the variable generation tie-breaking methodology used today. The future DAM calculation engine will provide the same required functionality. This methodology will continue to break ties according to a daily dispatch order.
636	Power Advisory	Section 3.5.3 – Variable Generation Resource Tie-Breaking [...] the Consortium believes that potential results of some generators that may change their offer behaviour and strategies based on the combination of the proposed -$100/MWh price settlement floor, SBG, and specific contract provisions and provisions with regulatory frameworks that additional tie-breaking rules could be required to determine which generators produce energy in real-time and which generators will be economically curtailed. Therefore, the Consortium recommends that IESO review tie-breaking rules under this potential scenario and be open to working with MPs and stakeholders to develop new fair and workable tie-breaking rules if warranted.	The IESO does not foresee any tie-breaking issues as a result of the settlement floor of -$100/MWh. The IESO will consult stakeholders if any changes to the tie-breaking rules are required.
637	Power Advisory	Section 3.6.1.6 – Constraints to Ensure Schedules Do Not Violate Reliability Requirements Under the Operating Reserve Requirements sub-section on pp. 70-73, it is not clear whether IESO can activate 'flexible' OR. Please clarify whether IESO can activate 'flexible' OR in DAM.	Flex OR is additional 30 minute OR that can currently be scheduled only in pre-dispatch and real-time to account for conditions such as uncertainty in system supply and demand forecast error. The ability to schedule Flex OR will be incorporated into the DAM as additional 30 minute OR requirement. This is stated in Section 3.4.1.4. The DAM calculation engine will ensure that sufficient resources are scheduled to meet the 30 minute OR, including any Flex OR, requirement.

ID	Stakeholder	Feedback	IESO Response
640	Power Advisory	Section 3.10.1.1 – Energy LMPs for Internal Pricing Nodes It is stated on p. 140 that "An energy LMP can fall outside the settlement bounds provided by EngyPrcFlr and EngyPrcCeil as a result of joint optimization or constraint violation pricing. When this occurs, the LMP and its subcomponents (reference, loss and congestion) will be modified so that LMP is within the settlement bounds." While the balance of this section provides algorithms to support the above point, clear numeric examples should be provided by IESO through stakeholder engagement meetings. This will help enhance discussions and understanding between MPs and stakeholders with IESO regarding what inputs can and cannot set LMPs. [...]	The price modification is required to ensure the settlement LMP is within the energy price floor and the energy price ceiling. This will occur after the calculation engine has determined the prices. As a result, the price modification process has no impact on price setting eligibility. Further information on price setting eligibility can be found in the Calculation Engines Pre-Reading for the stakeholder engagement session on August 27, 2020.