IESO Response to Feedback on MRP Energy Detailed Design Documents

Part 2: Grid and Market Operations Integration; Market Power Mitigation; Market Settlement; Offers, Bids, and Data Inputs

Below are the IESO's responses to stakeholder feedback on the Grid and Market Operations Integration, Market Power Mitigation, Market Settlement, and Offers, Bids, and Data Inputs detailed design documents. The feedback is organized by design document, and then alphabetically by stakeholder. This document covers the remaining comments that stakeholders submitted on the four detailed design documents. The IESO posted Part 1 of responses on October 19, 2020.

Contents

General Feedback

ID	Design Document	Stakeholder	Feedback	IESO Response
216	General	OWA	[...]We appreciated the opportunity to review our initial comments with staff directly and have reflected our discussion in this submission. In addition to the specific items noted herein, we raised two (2) issues for consideration. First, the industry again recommended the development and implementation of an energy/operating reserve parameter. We understand that the IESO has acknowledged this recommendation and suggests that it is expected to be addressed in the detailed design document for the Day-Ahead Market Calculation Engine, once published. Second, the IESO should arrange a technical stakeholder session with the calculation engine vendor (ABB) and hydroelectric market participants to discuss the complexities of hydroelectric modelling in the Ontario market. Ontario is unique from other jurisdictions given the uniqueness of its hydroelectric fleet and the calculation engine design requires made in Ontario solutions that use existing resources to their full extent.	Yes, the Day-Ahead Market (DAM) Calculation Engine document addresses joint optimization of energy and operating reserve (OR). Regarding the second point, the IESO's work with the stakeholder community on the Detailed Design continues. The IESO will consider requests for additional meetings and discussions, and where there is a clear need, to bring relevant subject matter expertise to those potential discussions.

Grid and Market Operations Integration

ID	Design Document	Stakeholder	Feedback	IESO Response
468	Grid and Market Operations Integration	Capital Power	[…] the detailed design document lacks necessary details relating to the governance requirements that will apply to manual intervention by the IESO. Without clear governance controls limiting the frequency and type of manual interventions, it is not clear how price fidelity will be preserved. Weak governance controls on manual intervention decisions will affect a range of design elements, from the generation of demand forecasts to the scheduling of incremental operating reserve required for system flexibility, thereby impacting scheduling, pricing, and resource dispatches. Details of the governance framework should be published in the next round of detailed design documents. [...]	The same governance and controls that exist today for manual intervention will continue in the future and are not changing with MRP. The Market Rules, specifically Chapter 5 Section 1.2.1 General Principles, provide the overarching authority for the IESO to take actions for reliability. Chapter 5 Section 1.1.1.2 of the Market Rules sets forth the conditions under which the IESO shall have the authority to intervene in the IESO-administered markets. The conditions in which the IESO may manually intervene are generally found in Market Manual 4.3, Section 3 "Determining Real-Time Schedules", Market Manual 7.1 sections 2.1 and 2.4, and Market Manual 7.4 Sections 1.4, 2.7.1, 3.1, and 4.1. The IESO will add these clarifications, with Market Rule and Market Manual references, to version two of the detailed design documents.
469	Grid and Market Operations Integration	Capital Power	If the Pre-Dispatch ("PD") scheduling run starts at 20:00, it is unclear how Non-Quick Start ("NQS") generators with a cold start profile can or will receive a schedule for HE1. Should the PD calculation engine detailed design document not provide this information, Capital Power requests that the IESO clarify.	A Non-Quick Start (NQS) generator with a cold start profile will only receive a schedule from the 20:00 PD run for hour ending 1 if the lead time for cold thermal state is less than or equal to 3 hours. The timing of the 20:00 pre-dispatch (PD) run time was determined with consideration of the cold status of a NQS that may be required to meet a reliability need during the morning ramp.
472	Grid and Market Operations Integration	Capital Power	A parameter for maximum loading point for energy available to provide OR is required for MPM and pseudo unit modelling. Conflicts will occur with MPM and the restrictions under the ADE otherwise.	A parameter for maximum loading is not required because a new pseudo unit parameter has been developed that will help produce feasible reserve schedules. This parameter restricts 10-minute operating reserve from being scheduled in the duct firing region. Feasible reserve schedules are therefore expected to be achieved through offers, compliance aggregation and the new pseudo unit parameter. Further details on this new parameter will be provided in version 2.0 of the Facility Registration detailed design document.

ID	Design Document	Stakeholder	Feedback	IESO Response
474	Grid and Market Operations Integration	Capital Power	It is reasonable for the IESO to not permit revisions to associated values of respective start-up offers after that generator has received both financially binding schedules and operational commitments from DAM. However, it is not clear under what circumstances a generator will receive a financially binding schedule from DAM and not receive an operational commitment. If NQS generators do not receive an operational commitment they should not be restricted from revising their offers in PD and RTM (i.e., start-up, speed no-load and energy). Lifting these restrictions will improve market efficiency and better ensure resource adequacy in RTM. The IESO should consider more flexibility regarding offer revisions from NQS generators to enable better reflection of costs closer to real-time dispatch. Without additional flexibility to revise offers, even in some circumstances where NQS generators have been scheduled and/or committed from DAM, there may be instances where these generators will be forced to offer in higher prices in DAM if there is a possibility of cost increases between submission of DAM offers and real-time operations. Further, this needs to be considered within the economic withholding MPM framework.	There are no circumstances in which a NQS resource receives a financially binding schedule from DAM but does not receive an operational commitment for its minimum generation block run-time hours. As described in Section 3.3.7.3, offer price increase restrictions following 20:00 EST on the pre-dispatch day are limited to commitment costs only (start-up offer, speed-no-load offer and energy offer price for MW quantities up to and including minimum loading point). Revisions to incremental energy and operating reserve offer prices can be made up to the real-time mandatory window. Commitment cost increases restrictions following 20:00 on the pre-dispatch day are required to ensure consistency of hourly pre-dispatch schedules and commitments.
475	Grid and Market Operations Integration	Capital Power	Regarding revision rule exceptions, the IESO has proposed that where PSUs are operating in combined-cycle mode, that these PSUs may only switch to single cycle mode for RTM operations if the ST experiences a forced outage. More flexibility should be considered to permit single-cycle mode operations in RTM, if such change from combined-cycle operations enhances the generation facility's ability to best meet power system needs in RTM. This provision will be of mutual benefit to generators with this capability while enhancing market efficiency and supply adequacy. MLP changes should be permitted so that when a Combined Cycle Generator utilizes the Pseudo model, they may need to change their MLP based on the configuration they secured in the DAM. Pseudo units are modelled as independent 1x1 units which may have different limitations than 2x1.	While there are many advantages to modelling combined cycle facilities as pseudo units, there are some limitations in that the pseudo-unit (PSU) model cannot capture every operational characteristic of these plants. With the PSU model, market participants will have the ability to switch between single and combined cycle modes for new commitments, provided the PSU is offline and does not have a future commitment on the current dispatch day. While PSU may physically be able to switch between single and combined cycle modes while generating, calculation engines using pseudo units cannot recognize the transition intra day to switch and dispatch the new configuration correctly. The PSU model assumes a 1x1 configuration when the PSU is evaluated for commitment. Therefore, it cannot recognize differences in minimum loading point (MLP) due to different operational configurations. In situations where PSU are scheduled in a configuration that requires a higher MLP than is reflected in dispatch data, market participants have the ability to request a minimum generation constraint to prevent equipment damage (SEAL). To address these two limitations would require an overhaul of the PSU model with a different way of modelling combined cycle facilities.

ID	Design Document	Stakeholder	Feedback	IESO Response
476	Grid and Market Operations Integration	Capital Power	Offer price restrictions are reasonable after pre-dispatch commitments have been made to NQS generators. However, permitted exceptions should be allowed where supported by legitimate reasons (e.g., increase in fuel costs and/or applicable fuel services). What is the process to have the IESO approve offer changes based on fuel prices? This has the potential to be an administrative burden to both the IESO and the participant. Capital Power believes that changes should only require approval for MWs included in a binding schedule, and unscheduled energy or OR should not be bound by previous market conditions no longer observed.	As described in the detailed design technical session pre-reading materials dated November 1, 2019, offer price increases for dispatch hours that have received a pre-dispatch commitment will be permitted once a market participant has secured an increase to the resource's energy reference level. This will be done through the intra-day reference level revision process described in Section 4 of the Market Power Mitigation detailed design document. Procedures will be developed for this process during the Implementation Phase of the Market Renewal Program (MRP). Restrictions on offer price increases for MWs above a resource's binding PD advisory schedule are necessary because changes could inappropriately impact competition between resources. Once a NQS resource receives a commitment it holds a competitive advantage over other NQS resources that do not have a commitment. This is because subsequent runs of the PD scheduling process and the real-time market will consider the resource's start-up and speed-no-load offers sunk for committed units.
479	Grid and Market Operations Integration	Capital Power	In order to help maintain power system reliability, the IESO may require certain generators to be on-line and/or generating at a certain output level. The IESO has proposed that this requirement, when needed, will be an input to the DAM calculation engines. Considering the locations of some assets with proximity to load centres and the potential to be in a constrained area, there may be potential for the IESO to determine that certain assets will be needed on-line through the above manner to help meet power system reliability needs. This will occur more often for some generators than others. Accordingly, more details are needed regarding when the IESO will require certain generators to be on-line and how the IESO will determine which generators will be needed on-line.	The process to commit units for reliability will not change in the future market. Reliability commitments may be utilized under certain system conditions that are not recognized by the calculation engine but require certain generation facilities to be in-service and generating above a certain output to maintain reliability. When more than one resource can satisfy the reliability needs for the next day, the IESO will perform, to the extent possible, a least-cost evaluation to determine the resource(s) that will have a reliability commitment applied.

ID	Design Document	Stakeholder	Feedback	IESO Response
482	Grid and Market Operations Integration	Capital Power	When an NQS DAM commitment is passed to the PD a minimum constraint is put into the schedule for MLP and MGBRT. If RT/PD prices drop and a Generator loses their schedule following the constraint, the design may impose on a Generator a financial liability if prices subsequently spiked after being dispatched to shut down. Can the IESO please clarify?	If a generator is no longer scheduled after a DAM-issued minimum generation block run-time minimum constraint is completed because prices have dropped below their offer prices, the generator will be dispatched off. The market participant will be paid for their day-ahead schedule based on their day-ahead locational price. For hours in which the generator did not produce, they will then buy back their DAM schedules for these hours at the lower RT prices. Market participants can manage the risk of being offline if a subsequent price spike occurs in their DAM scheduled hours by reducing their start up and minimum load offers. This would increase the likelihood of being committed and dispatched in pre-dispatch and real-time. The ability to decrease offers will be made explicit in version 2 of Grid and Market Operations Integration (GMOI) in Section 3.3.7.3. These revisions will be allowed following the publishing of DAM schedules and before the start of the real-time mandatory window for the applicable dispatch hour, subject to revision rules described in Section 3.3.7.3 of the GMOI detailed design document.
484	Grid and Market Operations Integration	Capital Power	NQS resources sometime double cycle, which provides the system with flexibility to cover a morning and an afternoon peak. The process described on page 69 highlights the need for the IESO to add a fourth state for NQS generators. Full Speed No Load (FSNL) will allow generators to ramp back up for a second start much quicker than a hot start, providing the system with greater flexibility. For similar reasons, generators should be allowed to select Single Cycle mode within the dispatch day.	At the NQS Lead Time technical session, stakeholders recommended that the IESO include two additional thermal states in the design to represent very cold and Full Speed No Load (FSNL) states, for a total of five thermal states. While the new calculation engines will provide significant improvements over today's engines, the calculation engines are not capable of evaluating more than three thermal states. As such, the design includes three thermal states. Market participants will, however, have the ability to vary their dispatch data for each of the three thermal states, which provides an alternate way to reflect very cold and FSNL states. 'Very hot' dispatch data values that reflect FSNL conditions can be submitted as long as those values fall within validation rules for a 'hot' state. Validation rules are listed in Section 3.4.2 of the Offers, Bids and Data Inputs detailed design document. For example, 'hot' lead time and 'hot' down time values of zero can be used to reflect FSNL conditions. This value tells the PD calculation engine that the resource is available to be started again in the immediate hour after the resource's minimum run time is met for the previous start. Single cycle mode is also a daily dispatch data parameter which may also be revised after the DAM schedules are published and within the dispatch day. See Section 3.3.7.6 of the GMOI detailed design document for more details on single cycle mode.

ID	Design Document	Stakeholder	Feedback	IESO Response
485	Grid and Market Operations Integration	Capital Power	If a generator has received two separate schedules in the DAM, they will have financial exposure if they do not deliver on their schedule. The decommitment process appears to put a generator at risk of not meeting that schedule. If the generator is dispatched economically beyond the end of their first schedule, they may run out of time to cycle and meet their second schedule. Bridging the schedule seems to be at the discretion of the IESO. This will present DAM/RT financial risk, opportunity costs, and potentially contract risk to generators that are unmanageable.	The decommitment process does not put a market participant at risk of not meeting their future DAM commitment. If the real-time calculation engine continues to dispatch a NQS generator beyond its pre-dispatch scheduled hours, and it conflicts with the Minimum Generation Block Down Time (MGBDT) for a future DAM commitment, IESO operators will be automatically notified through control room tools. At that point if there is no reliability need, the IESO will apply a flag in the real-time calculation engine to dispatch the NQS down in real-time. This means the NQS will be able to operate to respect both the submitted MGBDT and the future commitment.
486	Grid and Market Operations Integration	Capital Power	The retirement of the RT-GCG will not eliminate the need for replacement offers. If a unit trips and another unit is available to replace it, that option should still exist. The design description indicates it is unnecessary because the system will evaluate a replacement unit economically, however this may not be the case due to timing. A participant should be able to replace the forced-out unit using the same offer prices. This may require opening the mandatory window to allow adjustments and a manual constraint to be applied to meet the timing.	The Replacement Energy Offers Program (REOP) will continue to exist in the future market. Market participants will continue to have the ability to update offers within the mandatory window for the replacement unit. Likewise, the IESO will continue to apply a minimum generation constraint on the replacement unit for the current dispatch hour, until replacement offers take effect. This allows the pre-dispatch scheduling process to economically schedule resources based on the revised dispatch data submitted during the mandatory window. The commitments for both the forced-out unit and the replacement unit, if committed, will be automatically settled as per the design in the Market Settlement detailed design document, Sections 3.7.5, 3.7.9 and 3.7.11.
305	Grid and Market Operations Integration	Evolugen	The IESO should consider reducing the length of the mandatory window for intertie bids/offers and for internal generators. A shorter window, as is in place in other ISOs, would allow generators and marketers to better react to market price signals in real time, and improve overall market efficiency.	The IESO considered the cost, effort, and impact to project schedules associated with customizing the engines to reduce the length of the mandatory window, along with the benefit to market participants and the IESO. While this initiative is an important consideration to intertie traders and internal generators, it will not be included within the scope for the Market Renewal – Energy project.

ID	Design Document	Stakeholder	Feedback	IESO Response
330	Grid and Market Operations Integration	OPG	Ontario Power Generation's (OPG)'s detailed review comments for the Grid and Market Operations draft detailed design are provided in the table below. The following list provides a brief summary of the main themes in our comments. OPG looks forward to working with the Independent Electricity System Operator (IESO) to address/mitigate the issues we've identified so the final design can maximize market efficiency and minimize costs to ratepayers. More details on each of the following items is included in the detailed review comments. a) First run of the pre-dispatch (PD) engine at 20:00 is too late in the day to update hydroelectric offers to reflect evolving water conditions and plan effectively for next day's water. OPG proposes this be changed to 18:00 to allow more flexibility and time for adjustments prior HE1 of the next dispatch day. b) Design characteristics will require the use of outage slips to de-rate capacity for changes in head & flow conditions, which would require excessive submission of outage slips. This could become unmanageable for both market participants and the IESO. c) The design details imply that hydroelectric facilities can spill as a normal course of action and are dispatchable on 5-minute intervals. Sluice gates were not designed to be dispatchable at this frequency and should not be considered as a tool to facilitate dispatch instructions.	Responses to your comments are addressed as follows: a) Re the first run of the PD engine at 20:00 - a response to this comment can be found in the response to item GMOI item 346. b) Re the outage slips - a response to this comment can be found in the response to Offers, Bids, and Data Inputs (OBDI) item 136 c) Re Hydroelectric spill - a response to this comment can be found in the response to OBDI item 136

ID	Design Document	Stakeholder	Feedback	IESO Response
331	Grid and Market Operations Integration	OPG	Hydroelectric operations are complex due the dynamic nature of water conditions, operating restrictions, cascade dependencies and the various environmental/regulatory constraints that need to be respected. These changes to conditions can occur throughout the day, with various inputs required from a variety of entities. In today's nonfinancially binding day ahead commitment process (DACP) energy limited resources (ELRs) such as hydroelectric facilities have a second offer window to revise offers to ensure schedules are feasible before the final day-ahead (DA) engine runs to mitigate the identified risks. OPG believes a 2nd Offer Window is needed to address many of these issues and to help create a more accurate picture for the day ahead market (DAM). Without this 2nd offer window participants will be forced to offer into the market less effectively/efficiently, as they may not have all the required information (e.g. from various regulatory stakeholders) to make financially binding decisions in the DAM. In previous stakeholder engagements the IESO committed to building a hydroelectric optimization module that would incorporate a set of hydroelectric parameters as constraints with its DAM and enhanced real-time unit commitment (ERUC) engine vendor. However, after reviewing the detailed design documents thus far, the hydroelectric parameters will only account for a few circumstances, and the frequency of which changes can be made to the parameters falls below the necessary requirements to operate hydroelectric resources/facilities effectively. It is important the IESO understands the dynamic challenges hydroelectric facilities face when it comes to water management, and for these assets to be utilized effectively and efficiently to maximize the benefits to the system/consumer they need to be given flexibility. […] If a 2nd offer window for hydroelectric resources isn't implementable, OPG recommends the language around changing/modifying hydroelectric parameters be changed to allow for more operational flexibility. The recommended changes to those parameters are provided in OPG's comment submission for the Offers, Bids and Data Inputs Detailed Design (see OPG's comments #11-17 from OPG's Offers, Bids & Data Inputs comments).	Consistent with the decision and rationale under the DAM high-level design, the resubmission window will not be retained. The new hydroelectric dispatch data parameters are provided for hydroelectric resources to determine feasible DAM schedules that respect the limitations of scheduling hydroelectric units. They will also provide efficient PD advisory schedules to help participants manage their resources as real time approaches. These new parameters uphold the intentions for the data as presented in the DAM high-level design. For additional operational flexibility, revisions to hydroelectric daily dispatch data inputs will be permitted from the time that DAM schedules and prices are published on the pre-dispatch day until the end of the dispatch day. Revisions to hourly dispatch data are also permitted following the publishing of DAM schedules up to the start of the 2-hour mandatory window. The IESO has responded to OPG's detailed comments on the new dispatch data parameters under the OBDI responses.
334	Grid and Market Operations Integration	OPG	The current market process of submitting AGC schedules and revisions to the IESO is a manual process that could be better automated during Market Renewal. Automation may reduce barriers to new technologies entering the AGC market. OPG proposes the IESO incorporate the submission of AGC schedules into the same tool/system used for offers/bids submission in the new market.	The IESO considered the cost, effort, and impact to project schedules associated with automating the process of submitting Automatic Generation Control (AGC) schedules, along with the benefit to market participants and the IESO. While this would benefit AGC providers by reducing administration efforts, it will not be included within the scope for the Market Renewal – Energy project.

ID	Design Document	Stakeholder	Feedback	IESO Response
336	Grid and Market Operations Integration	OPG	Figure 3-2 shows the real-time market (RTM) Mandatory Window as 110 minutes. The IESO should consider shortening the RTM mandatory window time frame from 110 minutes to 90 minutes. A shorter window would be beneficial to market participants as it would provide resources additional flexibility / time to adjust to offers based on changing conditions (e.g. hydroelectric flow, forced outages etc.). In NYISO, the mandatory window is only 75 minutes.	The IESO considered the cost, effort, and impact to project schedules associated with customizing the engines to reduce the length of the mandatory window, along with the benefit to market participants and the IESO. While this initiative is an important consideration to intertie traders and internal generators, it will not be included within the scope for the Market Renewal – Energy project.
337	Grid and Market Operations Integration	OPG	[…] OPG recommends that changes to daily dispatch data inputs should be permitted hourly for physical/operational constraints. Parameters such as Linked resources, time lag, MW ratio and forbidden regions can change hourly based on physical/operational constraints that impact head calculations such as inflows, available units, expected upstream/downstream discharges, etc. […]	Revisions to most daily dispatch data inputs will be permitted from the time that DAM schedules, commitments, and prices are published on the pre-dispatch day until the end of the dispatch day. As described in Section 3.3.7.6, changes to daily dispatch data parameters - except minimum loading point, minimum generation block run-time and single cycle mode - can be revised hourly during the Real-Time Market Restricted Window for Daily Dispatch Data. Revisions to data must include a reason for the change that meets specific criteria that will be defined in the market rules. The criteria will be generally consistent with the existing criteria for allowing dispatch data revisions during the two-hour mandatory window - refer to Market Rules Chapter 7, Sections 3.3.6, 3.3.8, 3.3.11; and Market Manual 4.2, Appendix B. Revised criteria for submission of new hydroelectric daily dispatch data parameters are described in the IESO's responses to OPG's feedback on the Offers, Bids and Data Inputs detailed design document. These same criteria can also be used to facilitate revisions to daily dispatch data.

ID	Design Document	Stakeholder	Feedback	IESO Response
341	Grid and Market Operations Integration	OPG	In section 3.4.1 the design states: "In the future market, there will be a single DAM calculation engine run. The IESO will provide IESO data inputs that reflect the best information available prior to the DAM submission deadline of 10:00 EPT. IESO inputs used by the day-ahead market will not be modified to reflect changing system conditions after 10:00 EPT. IESO inputs into the DAM calculation engine will only be modified after 10:00 EPT to correct an input error that results in invalid day ahead market results as discussed in Section 3.5.3.1, Re-running the DAM Calculation Engine." The IESO should clearly define and provide examples around what types of "input errors" will be modified after 10:00 EPT that would result in invalid DAM results. In section 3.5.3.1, Re-running the DAM Calculation Engine it states: "In the future day-ahead market, no changes to dispatch data will be permitted after 10:00 EPT, unless there is an IESO tool failure. During the DAM scheduling process, the DAM calculation engine will not be re-run for changing system conditions. Any changes will be considered in subsequent evaluation processes such as pre-dispatch." OPG believes conditions that warrant a re-run of the DAM Calculation Engine should include changes to system conditions such as transmission outages, which can drastically change the day ahead financially binding schedules for market participants. The IESO needs to model transmission constraints as accurately as possible in the day ahead to mitigate the buyback risk associated with infeasible day ahead schedules. MPs should not be held financially responsible for inaccurate constraint modelling. Becoming more inflexible in the future day-ahead market with regards to what necessitates a re-run of the DAM calculation engine could lead to market participants being more risk adverse in a financially bound DAM. OPG suggests the IESO investigate the need to provide reporting related to "balancing congestion", i.e. where there are differences in transmission congestion in the real time market as compared to the day ahead market. PJM provides a variety of reports related to balancing congestion, and charges associated with it.	The DAM will run once per day, producing one set of hourly financially binding schedules for the next day based on a snapshot of system conditions and market inputs at the time the day-ahead process is initialized (10:00 EPT). The DAM will not be re-run for changes to system conditions such as unplanned or forced transmission outages. Changes in system conditions can and do occur at any time after the DAM initializes, including during the DAM execution window and the hours after DAM financially-binding results are posted. The purpose of the real-time balancing market is to account for these changes, relative to what was known at the time of the DAM. A financially binding DAM will require additional pre-DAM validation of IESO inputs, and new internal checks will be in place to verify inputs prior to DAM execution. Any input errors discovered during DAM execution will be corrected so that DAM results reflect the data provided in IESO published reports prior to 10:00 EPT. Balancing Congestion will be reported as Congestion Rent and Loss Residuals, as described in Section 3.7.14 of the Market Settlement detailed design document.

ID	Design Document	Stakeholder	Feedback	IESO Response
344	Grid and Market Operations Integration	OPG	[...] The IESO should publish reliability constraints in private reports to market participants. This will allow market participants to reconcile make-whole payments in DA and RT markets. These reports should be published in DA, PD, and RT timeframes, as well as, part of Settlement data files.	The IESO will provide information on reliability constraints in market participant settlement statements or settlement data files to allow for reconciliation of settlement amounts. The IESO will provide information on reliability constraints during the day-ahead, pre-dispatch, and real-time timeframes. The specific mechanism for providing that information has not yet been determined, but it may be through existing market participant confidential reports. More details will be available during Implementation and will be communicated well in advance of go-live.
345	Grid and Market Operations Integration	OPG	In section 3.4.3 the design states: "The IESO will continue to monitor and update network model inputs related to: · outages; · equipment status; and · telemetry." There is an opportunity for IESO to revisit its network model logic to use hydroelectric unit breaker position directly to determine if a unit is synchronized instead of the inferred logic used in the current network model.	The design does not necessitate a change to the network model logic for hydroelectric resources. The IESO considered the cost, effort, and impact to project schedules associated with enhancing the network model logic, along with the benefit to market participants and the IESO. While this initiative is an important consideration to the dispatchable hydro community, it will not be included within scope for the Market Renewal – Energy project.
347	Grid and Market Operations Integration	OPG	The IESO adjusts the centralized variable generation forecast to better align with observed variable generation output trends and the design states that: "in the future, the IESO will apply overrides on a zonal basis to ensure that variable generation forecasts in each zone reflect conditions in each zone." The IESO should create a report to indicate when and in which zone the IESO is in manual or override mode to provide transparency to market participants. This will allow market participants to respond to variable generation forecast changes that could potentially impact the generation schedule.	The current Variable Generation Forecast Summary Report is issued approximately 5 minutes prior to every hour for the IESO Zones. This report captures any adjustments or overrides made by the IESO that were necessary to reflect conditions in each zone. The reporting frequency and level of detail in this report provides transparency for market participants to respond to variable generation forecast changes.
349	Grid and Market Operations Integration	OPG	The design states that the IESO will produce the existing province-wide demand forecast as the sum of the four separate demand forecast areas. Forecasting errors can be magnified at lower load levels and OPG suggests that the IESO continues to publish the traditional hourly province wide Ontario Demand forecast to compare how the new methodology compares to the current one.	The IESO considered the potential for forecasting errors to be magnified at lower load levels. This factor was one of the many variables used to determine the number of forecast zones. To support forecast accuracy in the four demand forecast areas, the IESO is providing additional inputs to the forecast models such as input from additional weather stations. The IESO will undertake due diligence steps prior to implementing the proposed demand forecasting process in market operations. The IESO will not continue publishing the province-wide demand using the existing process post MRP implementation.

ID	Design Document	Stakeholder	Feedback	IESO Response
352	Grid and Market Operations Integration	OPG	[...] If constraints are identified prior to the DA submission window, they will be applied as inputs into the DAM calculation engine. OPG is seeking clarification on what the result will be if the constraint identified in DA is no longer binding in pre-dispatch and real time. Will the constraints be maintained, or will the market participant be liable for the buy back in RT? If the constraint is captured in the DAM calculation engine, the constrained resource should be economic by virtue of the LMP price (Marginal Congestion Cost (MCC) component). Resources required in the DAM should never be scheduled uneconomically.	If the IESO cancels a DAM operational commitment, including reliability commitments, the registered market participant for the generation facility will be eligible to receive specific settlement make-whole payments. Please refer to Section 3.7.7 of the Market Settlement detailed design document for more details.
353	Grid and Market Operations Integration	OPG	The design states: "The ability to schedule Flex OR will be incorporated into the day-ahead market. A new process will enable the IESO to determine if Flex OR is required as well as the quantity for the day-ahead market and notification will be provided to market participants." This should be part of the reliability pass of the DA calculation engine and additional units required to provide OR should be scheduled accordingly. [...] OPG would suggest the IESO review their methodology of addressing system flexibility needs as the MSP has recommended the IESO re-consider its current approach and develop a long-term, cost-effective solution. The IESO should also ensure they consult and solicit input from stakeholders as part of their process with the OEB which can be done through various existing IESO stakeholder engagements (e.g. OR Accessibility, MRP).	Any Flex OR requirement identified for the DAM will be evaluated in all three passes of the DAM calculation engine, including the Reliability Scheduling and Commitment Pass (the reliability pass), and additional units required to provide OR will be scheduled accordingly. The IESO considered the cost, effort, and impact to project schedules associated with developing a long-term approach to address system flexibility needs, along with the benefit to market participants and the IESO. While this initiative is an important consideration, it will not be included within the scope for the Market Renewal – Energy project.
354	Grid and Market Operations Integration	OPG	[...] The IESO should publish a report rather than send notification when the DAM is re-run during a day; for transparency the report should include information on the revised inputs.	The IESO issues automated reports to inform market participant for events that occur often, are repetitive in nature, and occur at a predetermined frequency. Advisory notices are used to inform market participants of events that occur infrequently with no set or predetermined frequency. Advisory notices are issued at the time event occurs to provide immediate notification to the market participants. The re-run of DAM calculation engine is expect to occur infrequently with no predetermined frequency. Therefore, re-run of DAM calculation engine is an exception-based event where notification to market participant via advisory notices is the reasonable approach. During Implementation, the IESO will explore opportunities where possible - while adhering to confidentiality provisions - to enhance advisory notifications to include information as suggested on revised inputs utilized to re-run the DAM calculation engine.

ID	Design Document	Stakeholder	Feedback	IESO Response
355	Grid and Market Operations Integration	OPG	[…] Delays or failures of the DAM may lead to non-quick start units missing the opportunity to procure an appropriate amount of gas in the ID2 gas window that closes at 14:00 EPT. This may lead to increased costs to procuring gas that were not anticipated during day ahead submission timelines. OPG recommends the IESO create a process that allows market participants to recover their costs if the costs of the subject commodities increase due to the uncertainty caused by delays or failures of the DA calculation engine.	If the DAM is delayed or fails, there will not be an additional cost recovery process. The DAM is designed to complete prior to the 14:00 EPT gas nomination deadline. The DAM delay deadline of 15:30 EPT was determined while making considerations for the fact that market participants might need to procure gas at the later nomination deadline of 19:00 EPT to meet any IESO reliability commitments made subsequent to a DAM failure. This is a risk that occurs today, and is unchanged by the introduction of MRP. Market participants are expected to continue to consider the risk of a later nomination into how they offer their resources for a given dispatch day.
356	Grid and Market Operations Integration	OPG	Both Offers, Bids, and Data Inputs and Grid & Market Operations Integration Design Documents do not mention the number of forbidden regions that will be allowed for each resource type. In the current market there are only three forbidden regions per resource aggregate. OPG proposes this be expanded to at least 8 to reflect one resource that contains 8 units along with multiple resource aggregates that contain more than 3 units.	Five forbidden regions are the maximum number that can be supported by the calculation engines, considering all of the other new hydroelectric dispatch data parameters that have been included in the design.
357	Grid and Market Operations Integration	OPG	[…] OPG recommends the maximum number of starts per day is applied at the unit level. For example: if a resource type has 5 generating units then the number of starts would be the maximum number of starts per day submitted multiplied by 5. […] OPG recommends the IESO re-assess the default value of 24 depending on whether MNSPD is at the resource type level of the unit level. OPG recommends the Number of Starts Tracking Report is published on an hourly basis and should include IESO inferred number of starts per unit for a resource type with multiple generating units for all historic hours of the day on an hour by hour basis. This level of detail will allow market participants to proactively assess the accuracy of the inferred calculation. A process should also be developed that allows the market participant to either correct the number of starts as reported in the Number of Starts Tracking Report or NULL the Maximum Number of Starts per Day parameter through daily dispatch data submission. For example, starts related to return to service testing may exceed the number of starts per day submitted for a resource type that may limit its ability to generate in future hours resulting in market inefficiencies if market participants are not able to modify the parameter throughout the day.	The design does allow for market participants to manage Maximum Number of Starts Per Day (MNSPD) for an aggregated resource at the unit level. The IESO agrees that the maximum number of starts for aggregated resources should not be limited to 24. The IESO will update the Offers, Bids and Data Inputs design document to clarify that starts can be managed at the unit level for aggregate resources and modify the validation rules so that the maximum number of starts that can be submitted on an aggregated resource is less than or equal to 24 times the number of units in the aggregate. The Number of Starts Tracking report (as found in Publishing and Reporting Market Information Detailed Design Issue 1.0, Section 3.3.5, Table 3-7) will provide information on the actual and forecast number of starts at the market resource level, not at the generating unit level. The design allows for market participants to null or remove the MNSPD for future pre-dispatch runs in the event that MNSPD is exceeded and the market participant elects to keep the unit available. Report timing and details will be determined during implementation with input from market participants.

ID	Design Document	Stakeholder	Feedback	IESO Response
358	Grid and Market Operations Integration	OPG	With regards to Linked Resources, Time Lag and MW ratio parameters, please confirm the following: · Are linked resources based on aggregate or station level? For example, will MPs have the ability to link all units at Station X to Station Y, or can market participants link resources based on aggregates (i.e. injection point)? For example, Station X and Y each have 2 aggregates and Station X-AG1 is linked to Station Y-AG1 and Station X-AG2 is linked to Station Y-AG2? Certain hydroelectric stations are restricted in the number of units that can be dispatched to start/stop generating simultaneously, this effectively results in a delay between when units at the same station can be started. To produce a feasible schedule, OPG suggests the ability to link aggregates belonging to the same station (e.g. link AG1 and AG2 belonging to Station X), with an appropriate lag between unit starts/stops to reflect this restriction. OPG welcomes further discussion or alternative solutions to address the operational concern.	Resources can be linked at the station level. Station-level linkage is enabled when a market participant registers that two or more resources share a forebay. An upstream set of one or more resources that are registered to share the same forebay may be linked to a downstream set of one or more resources that are registered to share the same forebay.
359	Grid and Market Operations Integration	OPG	[...] The IESO should publish private reports including the most restrictive constrained areas regardless of whether a mitigation event occurs. This is required since the make-whole payment mitigation test is independent of mitigation events and depends on the thresholds for the most restrictive constrained area.	The IESO will provide market participants with a confidential report when any mitigation actions were taken by the DAM calculation engine for their resources. This report, along with published day-ahead market schedules and commitments for market participant's applicable resources, will assist them in understanding how their resources were scheduled for the next dispatch day. The IESO will not publish information on most restrictive constrained areas where no mitigation actions were taken. Publishing this information from the DAM calculation engine may provide opportunities for inappropriate conduct.
367	Grid and Market Operations Integration	OPG	Figure 3-22 provides an example of a binding start up instruction with the generator requiring two hours to ramp up to MLP. OPG proposes that market participants should be able to provide multiple 'Ramp Up Energy to MLP' inputs for this parameter. For example, HE15 - 20 MW and HE16 - 200 MW should not be represented linearly by 110 MW (the average) for each hour. From this example, the use of average ramp values causes discrepancies and market inefficiencies in both hours that may be avoidable by allowing two separate values for each ramp hour.	The IESO agrees that the 'Ramp Up Energy to MLP' should not be represented linearly. The Offers, Bids and Data Inputs detailed design document describes the 'Ramp Up Energy to MLP' parameter as consisting of: 1) the number of hours required to ramp to MLP; and 2) average quantity of energy in MWh that resource is expected to produce in each ramping hour. Figure 3-22 does not accurately represent the design and will be revised in version 2 of GMOI.

ID	Design Document	Stakeholder	Feedback	IESO Response
368	Grid and Market Operations Integration	OPG	OPG is concerned the use of predefined MGBDT & Lead times to determine a future commitment may not accurately reflect the condition of a plant. The condition of thermal plants may vary start-to-start, and thus modifications to hot, warm and cold lead times may be necessary during the day. OPG requests the IESO publish an hourly standardized confidential report to indicate the inferred state of a NQS unit and suggests that a mechanism be put in place that allows modification of the lead time throughout the day to ensure the accurate state is reflected in the market.	The IESO agrees that a confidential report to indicate the inferred state of a resource is required for transparency. This new confidential report will be included in V2 of the Publishing and Reporting detail design document. The design allows market participants to modify the Lead Time parameter throughout the day, subject to revision rules as outlined in Section 3.3.7.6 of Grid and Market Operations Integration detail design chapter.
369	Grid and Market Operations Integration	OPG	[…] The proposed design could make market participants financially responsible for not meeting a DAM commitment through no fault of their own. If the IESO commits a NQS unit ahead of its DAM commitment, the unit should be constrained on to at least its MLP until the start of its of DAM commitment if it is unable to respect its MGBDT if it is de-committed from the first stand-alone PD operational commitment. […] If the MGBDT cannot be respected to re-synchronize a unit in time to meet its DAM financially binding schedule, the NQS should be constrained on to its MLP until the start of its DAM commitment.	In the event that a NQS resource has two commitments in a dispatch day, the IESO will not dispatch a unit that puts a minimum downtime requirement at risk. Specifically, the minimum downtime required for a NQS will be respected in order to resynchronize a unit in time to meet its DAM commitment. If this is not possible, the IESO will keep the generation unit in-service until the future commitment starts. Version 2 of the Grid and Market Operations Integration design document will be revised to clarify this process.
370	Grid and Market Operations Integration	OPG	OPG understands the IESO may cancel a DAM or pre-dispatch operational commitment at any time for reliability, security or adequacy reasons. A facility may be financially out of pocket if the cancellation of an operating commitment results in charges for placing unused gas back into storage. These charges, which are directly associated with an IESO cancellation of a DAM or pre-dispatch commitment, should be recoverable through a make whole payment. In Market Settlements Design, section 3.7.9, the design states: "In the event that a generation unit is de-committed subsequent to receiving a binding start-up instruction, the generation unit will be compensated for any lost opportunity during the de-committed period through RT_MWP." Details on the definition of the "de-committed" period are required - it should include ramp up energy to MLP, minimum generation block run time, and ramp down from MLP. A process is also required for market participants to recover costs not covered by real-time make-whole payments, such as, charges incurred for placing unused gas back in storage.	In the event that a resource is de-committed after receiving a binding start-up instruction for a pre-dispatch commitment, the resource will be eligible for a Real-Time Generator Offer Guarantee and a Real-Time Make-Whole Payment for the period that the resource was above its minimum loading point after being dispatched to come offline. The period to bring the resource offline from its minimum loading point will be covered by the Ramp-Down Settlement Amount. In the event that a resource is de-committed by the IESO for reliability or security reasons prior to the start of a DAM or pre-dispatch commitment, the market participant will be able to submit claims for the reimbursement of any financial loss that are associated with the de-committed resource. This is similar to the settlement mechanism that exists today for Day-Ahead Commitment Process Fuel Compensation but is being extended to the real-time market. More information on the settlement process will be provided during implementation.

ID	Design Document	Stakeholder	Feedback	IESO Response
372	Grid and Market Operations Integration	OPG	The design shows that current hydroelectric daily dispatch data can only be revised hourly for the rest of the day due to a SEAL reason. OPG continues to propose that the hydroelectric parameters be expanded to allow for physical/operational constraints and allow market participants to make changes to the hydroelectric dispatch data with every hourly submission. Minimum & Maximum Daily Energy Limits (DELs) […] the MIN and MAX DEL amounts are reported in MWh whereas water management plans deal with volumetric amounts. The DEL parameter will need to be evaluated hourly based on the actual volume of water discharged, not MWh produced. Market participants will need the ability to modify the MIN and MAX DEL parameters hourly to true up the inherent differences between the units of measurement used. […] Maximum Number of Starts Per Day […] Market participants should be given the opportunity to update/correct the number of starts parameter on an hourly basis to ensure accurate dispatch data is used in the pre-dispatch calculation engine. […] Forbidden Regions […] Hydrological changes including inflows, discharges, headwater and tailwater levels are some of the parameters that affect the hourly calculations of efficiency and capacity. As a result of these hourly changes, OPG recommends that market participants are able to modify forbidden regions on an hourly basis. […] Linked Resources, Time Lag and MWh Ratio […] Although the physical distance between resources on a cascade river system are fixed, the time lag and MWh ratios can vary due to variables including but not limited to: wind velocity, inflows, and the differences between tailwater elevation of an upstream resource and the headwater elevation of the downstream resource. Hydroelectric conditions can vary throughout the day and market participants need the ability to modify and/or terminate linkages between resources during the day so that the intertemporal dependencies of cascade resources are accounted for in future PD runs. […] As hydroelectric conditions change, and unplanned outages and transmission constraints arise, market participants require the flexibility to modify the daily dispatch data parameters hourly to reflect physical operational restrictions.	Revisions to these hydroelectric daily dispatch data inputs will be permitted from the time that DAM schedules, commitments, and prices are published on the pre-dispatch day until the end of the dispatch day. As described in GMOI section 3.3.7.6, changes to daily dispatch data parameters can be revised hourly during the Real-Time Market (RTM) Restricted Window for Daily Dispatch Data. Revisions to this data must include a reason for the change that meets specific criteria that will be defined in the market rules. These criteria will be generally consistent with the existing criteria for allowing dispatch data revisions during the two-hour mandatory window - refer to Market Rules Chapter 7, Sections 3.3.6, 3.3.8, 3.3.11; and Market Manual 4.2, Appendix B. The criteria are not limited to SEAL reasons (i.e. prevention of operating in a manner that would endanger the safety of any person, damage equipment, or violate any applicable law).

ID	Design Document	Stakeholder	Feedback	IESO Response
376	Grid and Market Operations Integration	OPG	The design has multiple references that require market participants to either request the IESO enter a minimum generation constraint or submit an outage slip in real time to manage the dynamic changes in head and flow conditions or hydroelectric resources. [...] As stated in comment #42, OPG recommends that the real time engine accept minimum constraints from the predispatch calculation engines to limit the number of minimum generation constraints requested or outage slips entered that can become unmanageable for both market participants and IESO in real time.	The Real Time calculation engine will be receiving minimum generation constraints based on the results of the most recent pre-dispatch run for the Hourly Must Run (HMR) input, as well as for the Minimum Daily Energy Limit input when required to do so. The remaining hydroelectric dispatch data will not be constrained into the Real Time calculation engine. With respect to feedback regarding the reliance on real-time must run constraints, responses are provided on the specific feedback received for each hydroelectric dispatch parameter under OBDI. In general, the design cannot allow for hydroelectric pre-dispatch schedules, other than those that reflect a must-run condition, to be reflected into the corresponding real-time hour as non-dispatchable quantities. Such constraints would preclude other dispatchable resources from being competitively evaluated to respond to changes in system conditions as the real-time hour approaches.
377	Grid and Market Operations Integration	OPG	If a generator is unable to meet its day-ahead commitment due to a circumstance outside of its control such as an unplanned/forced transmission outage, they should not be held financially responsible for the book-out. The Market Settlements design document states: “Under certain circumstances, a market participant with a DAM financially binding schedule may incur a financial loss as a result of an IESO control action on energy and operating reserve in real time. When this occurs, the IESO will provide a DAM Balancing Credit (DAM_BC) to cover any operating loss incurred as a result of following dispatch instructions.” The DAM_BC should apply under the above circumstances.	The DAM_BC is intended to protect the resource from any financial loss due to real-time buy-back as a result of IESO control actions to address reliability needs, it does not include situations such as unplanned/forced transmission outages. It is the responsibility of the generator to manage the financial risk associated with two-settlement in these situations. With two-settlement, financial gain as a result of an unplanned/forced transmission outage event would be retained by a generator therefore, financial risk of losses should similarly be retained by a generator. It should not be transferred from the generator to the consumer.
379	Grid and Market Operations Integration	OPG	[...] Please clarify if market participants will receive a make-whole payment if their continued operation during the bridge period between the two separate commitments is uneconomic.	The IESO will apply a minimum generation constraint when there is a reliability need to keep a NQS generation unit in-service between two commitments. During this bridging period, the reliability constraint will be considered a new commitment and both the Real-Time Generator Offer Guarantee (RT_GOG) and Real-Time Make Whole Payments (RT_MWP) will apply. Version 2 of the Grid and Market Operations Integration and Market Settlement documents will include settlement details for resources impacted by operator control actions. Like all reliability constraints, resources scheduled as a result of this constraint will be tested for local market power for make-whole payments. Refer to Section 3.8.3 of the Market Power Mitigation detailed design document for more information on mitigation of make-whole payments for reliability constraints.

ID	Design Document	Stakeholder	Feedback	IESO Response
381	Grid and Market Operations Integration	OPG	In regards to the last sentence of paragraph 2 under "Outages": "Registered market participants will have visibility on the impact of a physical unit derate or outage to the corresponding PSU through confidential market participant reports." OPG requests that the IESO issue confidential outage reports to show capacity after outages prior to DAM and for each pre-dispatch run. This will provide market participants transparency into which outages have been transferred into the IESO engines. The IESO has also created this additional reporting for pseudo units and recommends this be extended for all technology types as there may be translation/transfer errors in the IESO tools that require market participants to consider during outage and offer submission. This information may become significant as it could be used in MPM reference quantity calculations.	The methodology that is used for aggregated resources has no known issues at this time. Therefore, a similar report to Generator Data Computed Values Report for pseudo-unit is not presently required for other technology types. This translation process is transparent for hydroelectric resources with multiple physical units that are aggregated behind the same revenue meter. In this situation, when one of the units is on an outage, the available capacity of the aggregate is reduced by the capacity of the unit on an outage. In the event that translation errors in the tools emerge during Implementation we will address it then.
382	Grid and Market Operations Integration	OPG	In regards to the following statements from Section 3.8.1.3: "The IESO will also continue to initiate changes to commitments for reliability. Reasons for altering a commitment include: · Market participant initiated change to indicate a later MLP time due to unanticipated equipment failures; · Market participant initiated withdrawal of a commitment due to equipment failures; · Market participant initiated change to MLP or MGBRT due to SEAL concerns; and · IESO initiated withdrawal, delay, advancement or extension of a commitment for reliability." There should be a mechanism that allows market participants to recover their costs incurred from these changes including costs such as fuel transport & storage.	Market participants are not eligible to be compensated for costs incurred as a result of commitment changes initiated by the market participant. However, settlement mechanisms will be in place to mitigate any financial impact that may result from an IESO-initiated withdrawal, delay, advancement or extension of a commitment for reliability. Market participants will be able to submit claims for the reimbursement of any financial loss that are associated with a de-committed resource. This is similar to the settlement mechanism that exists today for the Day-Ahead Commitment Process Fuel Compensation. More information will be provided on the settlement process during implementation.
384	Grid and Market Operations Integration	OPG	[...] The IESO should provide a time interval for the manual procurement of operating reserve and details of how this will be settled. The OR should be scheduled on a 5-minute resolution and manually input into IESO tools to allow settlement.	The current process for manually procuring operating reserve is outlined in Market Manual 4.3 and will not change in the future market. The IESO will continue to verbally indicate to market participants the start and end times for manually procured reserve. Since this process is manual and executed during a busy period where tools are not available, it cannot be performed on a 5-minute resolution. Settlement of manually procured reserve will continue to be an after-the-fact process. As described in Section 3.9.3.2, prices and schedules will be reviewed to ensure they reflect any real-time corrective actions implemented by the IESO.

ID	Design Document	Stakeholder	Feedback	IESO Response
386	Grid and Market Operations Integration	OPG	Given the IESO will continue to manually intervene to respond to area control error (ACE) excursions, how will these interventions be communicated to market participants in a way that provides transparency? This is particularly important in the new market as it could impact a market participants financially binding day-ahead commitments, the eligibility for make-whole payments, and subject the market participant to further impact testing for make-whole payments.	When the IESO manually intervenes in real-time dispatch to respond to area control error (ACE) excursions, it is considered a reliability constraint. Resources scheduled as a result of a reliability constraint are eligible for real-time make whole payments. Transparency on reliability constraints and their settlement and mitigation impacts will be provided through settlement statements and data files, and new confidential reports for mitigation events.
388	Grid and Market Operations Integration	OPG	IESO should publish a report providing the details on flows for off-market transactions. This would make it easier for market participants to balance load equations in Ontario, which can be challenging given lack of details on offmarket transactions.	A specific report will not be provided as this information is already provided through other means. Most off market transactions such as SMO (Segregated Mode of Operation), SAR (Simultaneous Activation of Reserve), and inadvertent payback are implied in the flow values as part of the intertie transaction schedules and included as part of the Ontario Demand equation. Emergency energy purchases or sales are also published as an Advisory Notice on the IESO website.
390	Grid and Market Operations Integration	OPG	[...] The design should include more details and clarity on what additional control actions may be introduced in the new market.	If any additional emergency control actions are identified as necessary for the future market, they will be communicated to stakeholders through the Implementation phase of MRP.
392	Grid and Market Operations Integration	OPG	In regards to the final two paragraphs in this section (3.9.2): "However, if PD fails for two hours or more, the IESO will only be able to implement the DAM intertie transaction schedules that align with transactions present in neighbouring jurisdictions for the RT intertie checkout. No new incremental transactions that are scheduled in neighbouring control areas will be included in RT." Under this situation, the last available PD schedule should be used for interties rather than the DAM intertie transactions schedule because the data from the last PD run will be more current.	In the future, the pre-dispatch calculation engine will be scheduling incremental intertie transactions in hours T+1 and T+2. All hours beyond T+2 will only consider DAM scheduled intertie transactions. As a result, when PD fails for two hours or more, using the last good run of pre-dispatch to confirm intertie transactions inherently will use DAM scheduled interties only, as that is what the last good run of pre-dispatch would have included. The IESO will revise the document to clarify this point.
393	Grid and Market Operations Integration	OPG	In order to provide transparency and allow for Market Participants to better plan for situations when forced into an electrical island, would the IESO please provide additional details regarding calculation of LMPs in an electrical island including: · The administrative pricing method (from Table 3-2) to will be used to calculate LMPs in an electrical island. · The methodology to be used will be applied to calculate LMPs for electrical islands created by forced outages. · The methodology used will be applied to calculate LMPs for electrical islands created by planned outages. Providing the methodology will provide transparency and allow for Market Participants to better plan for these situations or develop operational instructions of how to respond if planned/forced into electrical island.	The methodology used for price administration in an electrical island will be one of the six listed in Table 3-2. The determination of which methodology to apply is dependant on a number of factors. Consistent with today's price correction approach, the IESO will communicate via an Advisory Notice which pricing methodology was applied at the time of administration. In the event of an electrical island, market participants will continue to respond as they do today by following IESO direction and protecting their equipment. The chosen methodology for price correction in each island occurrence should not impact this behaviour.

ID	Design Document	Stakeholder	Feedback	IESO Response
611	Grid and Market Operations Integration	OPG	OPG recommends the Number of Starts Tracking Report is published on an hourly basis and should include IESO inferred number of starts per unit for a resource type with multiple generating units for all historic hours of the day on an hour by hour basis. This level of detail will allow market participants to proactively assess the accuracy of the inferred calculation.	The Number of Starts Tracking report (as found in Publishing and Reporting Market Information Detailed Design Issue 1.0, Section 3.3.5, Table 3-7) will provide information on the actual and forecast number of starts at the market resource level, not at the generating unit level. Report timing and details will be determined during implementation with input from market participants.
712	Grid and Market Operations Integration	OPG	Please clarify if additional Flex OR is procured, reserve requirement in RT will not be decreased as this would cause financial bookout complications.	Additional Flex OR that is procured in the DAM may be reduced in real-time if conditions no longer require flexible supply. Operating reserve requirements are inputs to the DAM calculation engine and may change during pre-dispatch and real-time to reflect changing needs as the dispatch hour approaches. In the case of OR requirements that are reduced from DAM into real-time, real-time prices in both the energy and operating reserve markets will reflect the reduced requirements, and the DAM two-settlement mechanism will apply as designed. In the case of reduced Flex OR in real-time, buying out a DAM position may result in a net benefit due to the reduced real-time prices.

ID	Design Document	Stakeholder	Feedback	IESO Response
499	Grid and Market Operations Integration	Power Advisory	Recommendations The following are the Consortium's recommendations. • More details and review are required regarding IESO inputs that can impact market-clearing prices. o In particular, IESO inputs relating to operating reserve (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 regarding how IESO actions could impact resource scheduling and dispatch instructions, and market-clearing prices. Process details are needed, particularly regarding how IESO makes decisions whether to adjust or activate these inputs. o A good example of this has been included in the most recent Ontario Energy Board's (OEB's) Market Surveillance Panel (MSP) report3 dated July 16, 2020 regarding how IESO secures additional OR for system flexibility. • Dispatchable hydroelectric generators, at times, will require additional flexibility to respect operating parameters. o Under specific conditions, dispatchable hydroelectric generators should be permitted to revise and/or deviate from respective Day-Ahead Market (DAM) schedules in pre-dispatch and/or in the Real-Time Market (RTM). This will better enable feasible schedules and commitments respecting the capabilities and operational parameters of these hydroelectric generators and improve efficiencies within the IAM. • IESO needs to acknowledge potential Surplus Baseload Generation (SBG) and negative pricing issues through commitments to develop specific design within MRP. o Some of the sub-zones in the Northwest and Northeast zones may experience significant hours of SBG and therefore may result in prolonged and very low negative prices. If this were to materialize, market inefficiencies may result along with power system operation issues in localized zones.	IESO inputs into the calculation engines reflect anticipated conditions. As conditions change, the inputs are modified to provide a more accurate input used to calculate prices and schedules. While a detailed methodology for deriving each input will not be provided, market participants will continue to have visibility of the forecasted values used by each calculation engine. This provides sufficient information for market participants to better align their offer strategies with system conditions. Dispatchable hydroelectric generators will have flexibility to revise their dispatch data and/or deviate from their DAM schedules in the RTM. Participants may revise their dispatch data to achieve desired real-time outcomes, subject to revision rules outlined in Grid and Market Operations Integration section 3.3.7. The DAM is a snapshot in time, and after the DAM resources are dispatched in real-time based on their submitted dispatch data. Deviations from DAM schedules are expected, especially when conditions change and real-time prices provide incentive to increase or reduce generation. Along with the many benefits of Market Renewal to increase efficiency and transparency, the detailed design includes a settlement floor price to reduce the potential impact of exaggerated negative prices on market outcomes. Please refer to the pre-reading material posted for the Aug 27 MRP Calculation Engine Webinar for more details on the settlement floor price.

ID	Design Document	Stakeholder	Feedback	IESO Response
505	Grid and Market Operations Integration	Power Advisory	Section 3.3.7.6 – Real-Time Market Restricted Window for Daily Dispatch Under the Revision Rules – Daily Dispatch Data sub-section, it states that: "Daily dispatch data submission within the daily dispatch data restricted window will not require IESO approval, but will be subject to meeting criteria to be defined in the market rules. Market participants will be required to include with their daily dispatch data submission the reason for the submission that must adhere to defined criteria." The above needs to be clarified regarding what are the criteria for daily dispatch data to be accepted by IESO within the restricted window. This is especially important for dispatchable hydroelectric generators that can submit daily dispatch data defining operating and economic parameters for real-time operations – which have implications for water management. Overall, hydroelectric generators should be afforded with flexibility to revise offer data to make efficient use of water availability or unavailability regarding real-time operations. This will also improve the efficiency of the IAM.	As described in Section 3.3.7.6, the criteria for accepting revisions to daily dispatch data during the real-time market restricted window will be generally consistent with the existing criteria for allowing dispatch data revisions during the two-hour mandatory window in the current market rules and market manuals. More specifically, the IESO expects that acceptable criteria for daily dispatch data revisions will include but not be limited to similar provisions to those stated in Market Rules Chapter 7, Sections 3.3.6, 3.3.8, 3.3.11; and Market Manual 4.2 Appendix B.
506	Grid and Market Operations Integration	Power Advisory	Section 3.4.2.1 – IESO Inputs Revised Based on Resource Schedules and Energy Flow This section states that: "… IESO will continue to derive and forecast these five inputs for use in the day-ahead market based on an assessment of conditions on similar days as they best reflect anticipated conditions". The five IESO inputs referred to above are: Maximum Import/Export Limits; Net Interchange Scheduling Limit; Lake Erie Circulation Forecast; Minimum/Maximum Area Operating Reserve; and, Operating Reserve Requirements. More information is needed as to why IESO plans to use forecasts based on conditions on similar days. While it may likely be the case that some of the five inputs have remained relatively static over previous years (e.g., Maximum Import/Export Limits, Net Interchange Scheduling Limit), other inputs have changed (e.g., Operating Reserve Requirements through IESO's ability to secure "flexible" OR). Further, more insight is needed whether other inputs may be forecast to change in the future which then may render using "similar days" not optimal or efficient. For example, will Lake Erie Circulation Forecast change over time as New York adds significant planned new VGs and retires coal-fired and gas-fired generators? If changing supply mix in New York has potential to change energy flows within New York's power system and potentially energy flows into and through Ontario's power system, "similar days" may not be as accurate as in the past.	Yes, long-term trends like changing generation patterns in New York may impact these IESO inputs. Such changes do not appear overnight, but occur gradually over time. When the IESO forecasts these inputs, we use historical data from the recent past which means the impact of long-term trends will therefore be accounted for. The best forecast for tomorrow is usually what actually occurred yesterday, although other factors like day of the week or impactful outages are also considered. This point will be clarified in GMOI v2.0.

ID	Design Document	Stakeholder	Feedback	IESO Response
507	Grid and Market Operations Integration	Power Advisory	[...] IESO needs to be more transparent when it secures additional 30R to help meet Ontario's power system flexibility and operability needs. While IESO secures additional 30R in today's IAM, and schedules this 30R in pre-dispatch and RTM, it also correctly plans to schedule 30R in DAM when it exercises its ability to do so – which will than impact DAM LMPs for energy and OR. Therefore, more clarity and transparency are needed regarding protocols when and how IESO secures additional 30R. [...]	As described in Section 3.5.4, a new process will be developed to determine if and how much Flex OR is required as an input for the DAM calculation engine. Changes will be incorporated into the market manuals during MRP implementation. Advisory notices will continue to be used to provide transparency to the market when Flex OR is scheduled.
509	Grid and Market Operations Integration	Power Advisory	Section 3.4.4.2 – IESO Adjustments to the Centralized Forecast While IESO is correct in retaining the ability to adjust "the centralized variable generation forecast to better align with observed variable generation output trends", it must establish clear and transparent protocols for when it may adjust the centralized energy production forecast for VGs, and commit to transparently reporting on when IESO adjusted forecasts and whether IESO intervention in this manner has impacted market outcomes (e.g., scheduling and dispatching resources, market-clearing prices, other payments, etc.).	Currently, transparency on the variable generation forecasting approach is provided in Appendix D of Market Manual 7.2. Specific to adjustments, Section 3 of this market manual notes that the IESO may disable the five-minute variable generation forecasting tool when the forecast differs from the actual output by at least 50 MW. If the five-minute variable generation forecasting tool is enabled or disabled, this is communicated via an advisory notice on the IESO's website. Transparency on the hourly wind forecast values used by the DAM and pre-dispatch calculation engines will be provided through the Adequacy report. Market manuals will be updated to indicate when the hourly wind forecast may be updated by the IESO. As one of the many inputs to the market, an updated variable generation forecast that better reflects actual variable generation output will result in a more accurate input used to calculate prices and schedules.
510	Grid and Market Operations Integration	Power Advisory	Section 3.5.2.3 – Reliability Constraints The Consortium acknowledges IESO's need, at times, to have certain generation facilities producing energy to maintain the reliability of Ontario's power system. However, more clarity and transparent details are needed as to when IESO requires certain generation facilities to be producing energy for reliability reasons and how IESO will apply this as a specific input within DAM, pre-dispatch, and RTM calculation engines, as this input could impact scheduling and dispatch of other resources (e.g., generators) and LMPs for energy and OR.	Where possible, the IESO will allow calculation engines to economically schedule resources to satisfy reliability needs. However, certain outage configurations and system conditions are not recognized by the calculation engines. In these situations, the IESO may need to manually constrain specific resources as inputs into the day-ahead, pre-dispatch and/or real-time calculation engines to ensure that the reliability need is met. When more than one resource can satisfy the reliability need, the IESO will perform, to the extent possible, a least-cost evaluation to determine the resource(s) that will be manually dispatched. Transparency is provided to the market through advisory notices when resources may be constrained for reliability events, as described in Market Manual 7.1.

ID	Design Document	Stakeholder	Feedback	IESO Response
515	Grid and Market Operations Integration	Power Advisory	Section 3.7.2.2 – Determination of Hydroelectric Generation Facility Real-Time Dispatch Instructions This section states that: "In the future market, the DAM and PD calculation engines will use all of the new hydroelectric dispatch data parameters to produce hourly schedules that respect additional operating constraints. Respecting the new dispatch data parameters will produce hourly DAM and PD schedules that hydroelectric generation facilities would be feasibly able to respond to if those schedules were to materialize as dispatch instructions in the real-time market." The Consortium supports the aspiration in the above statement, as operational constraints for hydroelectric generators must be respected when scheduling their energy and OR supply for RTM. However, as discussed in Section 3.6.2.3 – Determination of Hydroelectric Generation Facility Schedules in Pre-Dispatch above, operational constraints could change from the time DAM schedules have been set to the pre-dispatch hours ahead of real-time operations. Therefore, under conditions were operational constraints have changed, applicable hydroelectric generators should be permitted to revise offer data after receiving schedules from DAM, in order to better ensure the feasibility of these schedules for real-time operations. In the Consortium's submission commenting on the draft Offers, Bids and Data Input Detailed Design 1.0, comments under Section 3.4.2 – Generation Facility Dispatch Data to Supply Energy discuss why flexibility may be required regarding the new dispatch data. Therefore, technically making the case why revision of offer data enhances the operations of respective hydroelectric generators to better meet system needs in RTM therefore improving the efficiency of the IAM.	Revisions to hydroelectric daily dispatch data inputs will be permitted from the time that DAM schedules, commitments, and prices are published on the pre-dispatch day until the end of the dispatch day. As described in Section 3.3.7.6, changes to daily dispatch data parameters can be revised hourly during the Real-Time Market (RTM) Restricted Window for daily dispatch data. Revisions to this data must include a reason for the change that meets specific criteria that will be defined in the market rules. These criteria will be generally consistent with the existing criteria for allowing dispatch data revisions during the two-hour mandatory window - refer to Market Rules Chapter 7, Sections 3.3.6, 3.3.8, 3.3.11; and Market Manual 4.2, Appendix B. Revisions to hourly dispatch data are also permitted following the publishing of DAM schedules up to the start of the two-hour mandatory window.

ID	Design Document	Stakeholder	Feedback	IESO Response
516	Grid and Market Operations Integration	Power Advisory	Section 3.8 – System Operation Processes and Control Actions This section states: "In the future market [MRP implemented], … control actions are not expected to change significantly." Like all other Independent System Operators or Regional Transmission Organizations, IESO maintains a list of Emergency Operating State Control Actions (EOSCA)11 to ensure compliance with the North American Electricity Reliability Corporation (NERC) standard EOP-011-1: Emergency Operations12. IESO's application of some EOSAC items could impact market outcomes, such as market-clearing prices. For example, as noted by the previous IESO Market Pricing Working Group (MPWG)13 as Issue #006 –Effects of Emergency Purchases on the Market – captured circumstances when IESO purchased emergency energy to maintain the reliability of the IESO-Controlled Grid (ICG) and in parallel IESO reduced non-dispatchable load commensurate with the amount of emergency energy purchased. This had the result of actually lowering market-clearing prices despite tight power system conditions caused by undersupply of energy in the IAM – leading to counterintuitive market-clearing prices sending inefficient market signals. This issue was addressed through MR-0029614 where IESO could no longer lower non-dispatchable load commensurate with the amount of emergency energy purchased. IESO's ability to purchase emergency energy is listed as #16i on EOSCA15. Another example from MPWG is Issue #036 – Pricing In-Market Control Action OR (CAOR) – where IESO had been securing additional OR under specific OR deficit circumstances but this secured OR was not priced within IAM and therefore resulted in lower OR prices which is counterintuitive to the actual OR supply shortfall. This issue was addressed through MR-0023516 which allowed IESO to include an additional 400 MW of CAOR in the IAM with prices in order to improve accuracy of market-clearing prices commensurate with OR supply needs. The above two examples clearing show linkages between how IESO applies items within EOSCA and potential results of counterintuitive, inaccurate, and inefficient market outcomes (predominantly through perverse market-clearing prices).	IESO control actions are designed so that they do not result in counterintuitive market signals. Two commonly used control actions - manual resource constraints and intertie curtailments - have been designed to produce price signals that are appropriate for market and system conditions. Information on the impact of these actions on price setting eligibility can be found at the end of the Calculation Engine Technical Session pre-reading document. Further information on how the pricing pass is adjusted when the IESO employs other control actions such as load shedding, voltage reduction or when IESO implements emergency purchases that do not support a sale (emergency imports for Ontario) can be found in the Real-Time Calculation Engine detailed design document.

ID	Design Document	Stakeholder	Feedback	IESO Response
617	Grid and Market Operations Integration	Power Advisory	• Dispatchable hydroelectric generators, at times, will require additional flexibility to respect operating parameters. o Under specific conditions, dispatchable hydroelectric generators should be permitted to revise and/or deviate from respective Day-Ahead Market (DAM) schedules in pre-dispatch and/or in the Real-Time Market (RTM). This will better enable feasible schedules and commitments respecting the capabilities and operational parameters of these hydroelectric generators and improve efficiencies within the IAM.	As described in section 3.3.7.6 in the GMOI document, changes to daily dispatch data parameters (except minimum loading point, minimum generation block run-time, and single cycle mode) will be permitted at any time (i.e. they can be revised hourly) during the RTM restricted window for daily dispatch data. Revisions to data must include a reason for the change that meets specific criteria that will be defined in the market rules.

Market Power Mitigation

ID	Design Document	Stakeholder	Feedback	IESO Response
307	Market Power Mitigation	APPrO	[...] First, as mentioned in many of APPrO's past submissions, success of market renewal will also require renewing IESO's governance and decision-making processes to better align with a renewed market and the new risks, obligations and associated rules that will be imposed on market participants. [...] [...] there needs to be further discussion as to how MACD's enforcement powers under Chapter 3 will play a roll with new MPM rules. APPrO recommends that further dialogue is required on this matter so that market participants understand how MACD's authorities will interplay with those of the new MPM rules. More generally, APPrO believes additional dispute resolution mechanisms may need to be implemented that focus specifically on market power mitigation issues. The current dispute resolution process may be unnecessarily burdensome and protracted for the purposes of resolving issues with respect to MPM related issues. [...] There needs to be transparency in the determination/declaration of NCA/DCA/LMP areas to allow the market participant the opportunity to assess mitigation risks. The new physical withholding process may result in excessive outage slip submissions and create an onerous process. [...] It is important to establish a well defined interface and decision/appeal process between IESO and MACD including who performs the MPM review/audit to ensure there is no overlap to maximize efficiency and minimize costs for all concerned including the ratepayer c) The IESO should revisit all terminology used in setting conduct and impact thresholds to explicitly state whether it is the "greater of" or "lesser of" as this is an important distinction which is not clear in the detailed design. [...] d) The rationale for the thresholds used for conduct and impact testing should be provided by the IESO.[...]	The IESO has developed a proposal for an independent review process of reference levels and quantities. This proposal will be shared with stakeholders later in 2020. The process to designate and communicate Narrow Constrained Areas (NCAs) and Dynamic Constrained Areas (DCAs) will be found in the Market Rules and Market Manuals. The conduct thresholds are all designed to be the "lesser of" the two values shown for each relevant threshold. The Market Power Mitigation (MPM) design document will be updated to reflect this clarification. The proposed conduct and impact test thresholds are consistent with the MPM guidelines discussed during high level design and published in the single schedule market high level design document. They are informed by the practices of other jurisdictions, and (where applicable) are consistent with those in the current ex-post local market power framework. The thresholds become less permissive as competition is more restricted. Specific rationale for individual parameters can be found in the pre-reading materials from the September 27, 2019 and January 23, 2020 technical sessions.
311	Market Power Mitigation	APPrO	Additionally, we wish to note that the absence of a stable capacity procurement/retention mechanism [...] will also hinder future development as no investor would knowingly deploy capital in a market that does not enable a reasonable opportunity to recover costs let alone earn a return. Details of this framework must be developed alongside MRP-proposed changes to ensure continued system reliability and resource adequacy [...]	Mechanisms to provide long-term adequacy are currently under discussion with stakeholders as part of the IESO's Resource Adequacy engagement, and the IESO will monitor the interrelationship between the Market Renewal and associated engagements.

ID	Design Document	Stakeholder	Feedback	IESO Response
401	Market Power Mitigation	Capital Power	Capital Power supports the forthcoming IESO engagement regarding reference levels. Thresholds should also be included. • There is a lack of detail regarding how reference levels will be set or how the IESO established the thresholds for the C&I test. Capital Power is also concerned with the governance around these parameters. For these reasons, Capital Power supports the upcoming IESO stakeholder engagements on these details. • Additional clarity regarding dispute resolution should be included in the design as there is currently no defined process for stakeholders to work with the IESO to determine reference levels and quantities or if and how changes to those reference levels to account for cost would be handled (and whether these would be in a timely fashion). [...] • The design document notes that "[t]here may be extenuating circumstances where the market participant believes that the financial reference level that was used to determine their settlement outcomes was inappropriate." Capital Power strongly urges the IESO to provide more detail regarding what constitutes as "extenuating circumstance."	The IESO has begun its implementation engagement on reference levels and quantities. This engagement will provide detailed information regarding how reference levels will be determined. The proposed conduct and impact test thresholds are consistent with the MPM guidelines discussed during high level design and published in the single schedule market high level design document. They are informed by the practices of other jurisdictions, and (where applicable) are consistent with those in the current ex-post local market power framework. The thresholds become less permissive as competition is more restricted. Specific rationale for individual parameters can be found in the pre-reading materials from the September 27, 2019 and January 23, 2020 technical sessions. The IESO has developed a proposal for an independent review process of reference levels and quantities. This proposal will be shared with stakeholders later in 2020. Section 3.15 describes the referenced circumstances. In the event that a resource has been mitigated and the participants believes that the fuel cost that was used to determine its reference level did not reflect the eligible short-run marginal costs of the resource, a resource may submit a request, via the notice of disagreement process, to have its reference level updated with new cost information. This can result in the resource being settled based on its original, unmitigated offer.
403	Market Power Mitigation	Capital Power	Mitigation should apply to market participant by ownership only. • The proposed design has the potential to link together resources that have no common ownership or financial interest. For example, it appears that resources could be considered together simply because they use a common third-party vendor for services rendered. Capital power strongly opposes being assessed with unrelated resources for the purposes of market power mitigation and suggests revisions to align mitigation with ownership.	The participation and authorization detailed design document will be amended to provide additional clarity on the criteria for determining market control entities

ID	Design Document	Stakeholder	Feedback	IESO Response
404	Market Power Mitigation	Capital Power	Approach to mitigating operating reserve offers is inconsistent with current tools and other detailed design documents. • The proposed MPM framework appears to require participants to offer Operating Reserve capability at the IESO-determined reference Quantity. However, under Grid and Market Operations 3.3.4, this appears to be voluntary and at odds with the MPM framework. These requirements should be revised for consistency. • The IESO will need to make enhancements to dispatch and scheduling tools to include operating reserves as part of the MPM framework. Without tool enhancements, Capital Power is concerned infeasible schedules will result and/or MPM will be triggered regularly and unnecessarily. Please see Capital Power's submission following the Pseudo Unit technical session (March 2020).	The physical withholding framework does not create a requirement to offer operating reserve under the market rules. A resource that does not offer its available supply can be assessed for physical withholding. The result of an assessment can be a settlement charge. The operating reserve reference quantity represents the amount of operating reserve that a resource is able to supply to the market. The IESO encourages market participants to participate in reference levels stakeholder engagement for further information on OR reference quantities. Changes to the IESO's approach to pseudo unit scheduling of OR are intended to prevent infeasible schedules in the future market.
405	Market Power Mitigation	Capital Power	Proposed "Make-Whole Payment" mitigation scheme should be relaxed. • The MPM design proposes that MWPs will always be subject to mitigation regardless of whether the conduct and/or impact test is failed. Under NCA or DCA, all resources will be tested and by virtue of being tested a MP will be subject to MWP mitigation whether they failed C&I or not. This has the potential to cause mitigation on a constant basis and could be unduly discriminatory to resources located within certain regions. Capital Power recommends that the MWP mitigation scheme be relaxed until further design details about constrained areas are provided.	The MPM design outlines the circumstances that result in mitigation. Mitigation for price or make whole payment (MWP) impact occurs only when all of the following are true: -at least one condition is met for testing for market power mitigation; -a resource fails the conduct test; and -the relevant impact test is failed. The MPM design applies equally to all relevant market participants and resources. As per the MPM guidelines, the MPM design is intended to limit intervention to times when it is needed. The MPM design tests for mitigation only on occasions when specific resources may have market power and assesses whether those resource have failed a conduct test and an impact test prior to a decision to mitigate.
406	Market Power Mitigation	Capital Power	Non-financial dispatch thresholds require added detail. Exception provisions should also be considered. • Table 3-4 outlines the IESO-proposed conduct thresholds for non-financial dispatch data. It is unclear to Capital Power how the IESO established these thresholds but in some cases a resource may be required to deviate from these levels for operational reasons. In such cases, protocols for exemptions need to be included as part of the detailed design; however, none appear to be outlined. Capital Power, therefore, recommends that an electronic exception process be included as part of the IESO's design. • Operating Reserve restrictions need to be added to this data to avoid infeasible schedules and to apply MPM to OR. See Pseudo unit submission Capital Power (March 2020).	Non-financial reference levels represent the operational capability of the resource. These reference levels can be set on a seasonal basis. The conduct thresholds afford additional flexibility to address varying ambient conditions. The need for additional flexibility to address variations in operational capability should be brought into the reference level engagement. The IESO encourages market participants to participate in reference level stakeholder engagement for further information on OR reference quantities.

ID	Design Document	Stakeholder	Feedback	IESO Response
407	Market Power Mitigation	Capital Power	3.6.1 – Ex-Ante Mitigation for Energy Price Impact Design requires further consideration to avoid impeding price formation in constrained areas and requiring market participants to operate at a loss. • The proposed design could hinder price formation in constrained areas and result in perverse outcomes where prices fall during scarcity. In such conditions, the resulting prices should be higher than they otherwise would be absent congestion. This would be the correct price signal for a constrained area. • Capital Power also strongly recommends adding the objective that the mitigation framework not require market participants to operate at a loss. This is a key principle and should be included as a core objective.	Market power mitigation supports efficient price formation by helping to ensure that market prices reflect actual costs, rather than the exercise of market power. When competition is restricted in a local area, or province-wide, the ex-ante mitigation framework will result in prices that are aligned with the short-run marginal costs of resources. When mitigation is applied, offer prices are replaced with reference levels, which are based on the short-run marginal costs of a resource. Reference levels are then used to determine prices and schedules. Using reference levels in these circumstances results in efficient dispatch and prices.
408	Market Power Mitigation	Capital Power	Proposed design for assessing "Global Market Power" is incomplete and should include Quebec interties. • The Quebec interties are absent from the list of Reference Interties. From the June MRP webinar, the IESO confirmed that it intends to leave these interties out in assessing Global Market Power. Capital Power has concerns with the omissions. Not including these interties will likely trigger the condition to test for "Global Market Power" unnecessarily as they could provide effective competitive discipline to internal resources. • It is unclear how the IESO will determine if resources "can meet incremental load" (versus all other resources) under global market power. Capital Power recommends that additional clarity in this regard be provided.	The Quebec interties are not connected to a wholesale market and thus do not meet the criteria laid out in Section 3.6.1.3 Global Market Power Mitigation for Energy Price Impact. Resources that cannot meet incremental load are those that are already providing all the energy possible given the transmission constraints in effect.

ID	Design Document	Stakeholder	Feedback	IESO Response
409	Market Power Mitigation	Capital Power	[...] • [...] Capital Power strongly recommends that all thresholds for the OR conduct and impact test be aligned with those established for the energy market. This would incent more participation in the OR market from existing units and potential future development in flexible operating characteristics. • Setting a "no-look" threshold level of $15/MWh will subject participants with an OR reference level greater than $15 to constant mitigation testing. [...] Capital Power recommends that the IESO provide its rationale so stakeholders understand how the IESO deemed this and any other threshold as appropriate. • [...] Capital Power strongly encourages the IESO to provide more detail about how it intends on setting minimum area reserve constraints and whether these will be reported publicly in advance (e.g. day-ahead).[...] • Details around setting reference levels for OR are not provided. Capital Power urges the IESO to include these as part of the upcoming stakeholder engagement sessions regarding reference levels.	The operating reserve conduct and impact thresholds are consistent with those used in other jurisdictions. The operating reserve market has a relatively static and known demand and the suppliers of operating reserve are limited to those resources that qualify to provide reserves. These traits are similar to those that identify NCAs/DCAs for energy. Hence the global market power conduct and impact thresholds for operating reserves are similar to those of NCA/DCA for energy. For clarity, the no-look threshold for operating reserve prices refers to the operating reserve clearing price, not the reference level. This $15/MW condition assesses occasions when operating reserve prices are greater than $15/MW. This and other thresholds are consistent with those used in other jurisdictions as well as with the MPM guidelines published in the Single Schedule Market High Level Design document. Area reserve requirements will continue to be based on an assessment of conditions on similar days. They will be updated in PD and RT using resource schedules and energy flows calculated by each engine and actual energy flows in real-time. The IESO will revise the timing of the day-ahead (DA) Area Reserve Constraints report so that it is provided to market participants in advance of DAM rather than after the DAM completes. The IESO will continue to provide in PD and real-time (RT) on an hourly basis with the most current information available. The IESO encourages market participants to participate in reference levels stakeholder engagement for further information on OR reference levels.
412	Market Power Mitigation	Capital Power	Proposed MWP-mitigation framework appears redundant and should be removed. • The proposed thresholds for operating reserve MWPs appear to be identical to those of the OR C&I test. Assuming the OR offer remains the same, passing the C&I test would yield the same result in the MWP mitigation framework. Therefore, it is unclear why mitigation is necessary as part of the MWP framework and should be removed.	There is an important difference between what the price impact test is assessing and what the make-whole impact test is assessing. The price impact test assesses whether price was greater with offered dispatch data than with reference levels. The make-whole payment impact test assesses if make-whole payments were greater with offered dispatch data than with reference levels. Both require a failed conduct and impact test before mitigation is applied.

ID	Design Document	Stakeholder	Feedback	IESO Response
413	Market Power Mitigation	Capital Power	Proposed energy market physical withholding framework is unnecessarily administrative and should be replaced with a "must-offer" requirement. OR participation should remain voluntary. • [...] The proposed ex-post mitigation for physical withholding appears to retain the Availability Declaration Envelope ("ADE") and creates a redundant requirement. Maintaining the ADE is the equivalent to a "must-offer" requirement but with far less administrative burden compared to the proposed approach. Capital Power, therefore, urges the IESO to preserve the existing ADE construct and discard the proposed physical withholding framework in its entirety. •[...] Capital Power recommends that the IESO consider revising its physical withholding requirement with the same rationale – align the requirement with the product by applying it those with a contract or some form of capacity commitment while granting an exception to those resources that have no such additional sources of revenue or guarantees. Similarly, Capital Power strongly believes that participation of any resources in the OR market should remain voluntary. Resources not capacity-committed should also be exempt altogether.	The physical withholding framework is intended to provide a disincentive for any market participant to physically withhold. Physical withholding can result in increased market prices. The persistence multiplier increases intervention where appropriate and is consistent with the market power mitigation guidelines. The availability declaration envelope (ADE) restricts market participants from offering MWs into the real-time market that were not offered in the day-ahead timeframe. It does not discourage market participants from physically withholding in both the day-ahead and real-time timeframes. It is not equivalent to a must-offer, or to the physical withholding framework.
415	Market Power Mitigation	Capital Power	3.9.2.1 – Persistence Multiplier for Physical Withholding Settlement Charges This design element is unnecessary and should be removed. • For the reasons noted above, the proposed physical withholding framework is overly administrative and unnecessary if replaced by a simple "must-offer" requirement via the ADE. • Should the IESO maintain this design element, additional details are required particularly around governance since it appears the IESO may exercise discretion as to when it will apply the test. Application of this framework must be transparent.	The physical withholding framework is intended to provide a disincentive for market participants to physically withhold. Physical withholding can result in increased market prices. The persistence multiplier increases intervention where appropriate and is consistent with the market power mitigation guidelines. The ADE restricts market participants from offering MWs into the real-time market that were not offered in the day-ahead timeframe. It does not discourage market participants from physically withholding in both the day-ahead and real-time timeframes. It is not equivalent to a must-offer, or to the physical withholding framework. The IESO has a limited time period of 6 months from the relevant dispatch day to notify the market participant of a potential settlement charge related to a failure of the conduct and impact tests for physical withholding.

ID	Design Document	Stakeholder	Feedback	IESO Response
417	Market Power Mitigation	Capital Power	Revisions to the governance framework needed to ensure disputes are identified and resolved within a reasonable timeframe. • The timing proposed in the procedural steps do not appear reasonable. First, the IESO notification period of six months is excessive. Stakeholders should not be made vulnerable to such an extended period of review. Capital Power believes that this requirement is likely due to the overly complex framework that is being proposed and could be resolved by focusing the framework on areas of most value. • After the 6-month IESO review period, however, stakeholders are only afforded 15 business days to collect and provide evidence to initiate a dispute. The IESO is then afforded another 3 months to make its final determination. The timing presented does not appear workable. Capital Power recommends that proposed process and timing be revisited and revised once details of the mitigation framework have been established.	The IESO has developed a proposal for an independent review process of reference levels and quantities. This proposal will be shared with stakeholders later in 2020. The IESO has limited resources to assess ex-post mitigation. Therefore, it may apply a conduct test as described in Section 3.9. The IESO has a time limit of six months to conduct such an assessment and notify the registered market participant of a potential settlement charge (Section 3.11). Please note that the current local market power framework, which is also conducted ex-post, does not have a limitation period. The IESO has increased the amount of time that participants have to prepare submissions for assessments of physical withholding from 15 to 30 business days.
421	Market Power Mitigation	Capital Power	The proposed timeline to update reference level values should be fair and practical. • Language in the design document should clearly state that updating non-financial reference level values is to occur after the market participant becomes aware of the change. In some cases, 5 business days may not be practical. Capital Power suggests that the IESO work with market participants to establish a fair and practical timeline to report changes in these parameters.	The IESO will update the text in this section to address this suggestion. The updated language will state that changes to non-financial reference levels should be made no later than five business days following completion of testing and commissioning. This will replace the current language which states that changes to the non-financial reference level will be made no later than five days after the operational change is made to registration data.
422	Market Power Mitigation	Capital Power	Additional changes to registration data or proposed OR reference levels may be required. • Participation in the OR market should remain voluntary. However, if mandatory, registration data will need to add limits to OR or else reference level for OR will need to be set to zero. (See Capital Power submission on pseudo units, March 2020).	Participation in the energy and operating reserve markets will remain voluntary. Creating a physical withholding framework does not create an obligation under the market rules to offer supply in either market. The reference quantity for operating reserve will be based on the operational capability of the resource. The IESO encourages market participants to discuss this issue during the reference level and quantity engagement.
306	Market Power Mitigation	Evolugen	The IESO should consider allowing hydro and energy limited resources the flexibility to manage their operations without over triggering mitigation flags.	The methodology for determining reference levels, including how to account for opportunity costs for energy limited resources, is being discussed in the reference level implementation stakeholder engagement.
395	Market Power Mitigation	OEA	When will the IESO communicate whether a separate dispute resolution mechanism will be established to address mitigation disputes? What types or forms of dispute resolution mechanisms is the IESO currently considering to address mitigation disputes?	The IESO has developed a proposal for an independent review process of reference levels and quantities. This proposal will be shared with stakeholders later in 2020.

ID	Design Document	Stakeholder	Feedback	IESO Response
169	Market Power Mitigation	OPG	It is important that the decision making process to address market power mitigation is efficient with appropriate governance. Market participants will be taking on additional risk with the implementation of Market Renewal and will need confidence in the proposed approach used to review offers. [...] OPG requests additional information on how the new market power mitigation rules will be integrated with existing MACD enforcement. [...] At the meeting with the OWA on July 8, the IESO took the action to provide details on who will be responsible for market power mitigation and compliance in the new market (i.e. is it MACD or the IESO). [...]	As noted in Section 2.2.4, the IESO's review for market power mitigation, including testing and any related steps taken by the IESO, will not constitute a review for compliance with any market rule, including Chapter 1, Section 10A - General Conduct or Section 11 - Information Disclosure. A business unit within the IESO's Market Assessment and Compliance Division (MACD) will be responsible for approving reference levels and quantities as well as the ex-post mitigation processes.
170	Market Power Mitigation	OPG	OPG appreciates and looks forward to negotiation with the IESO on the reference levels for physical withholding. Similar to economic withholding, in the determination of these levels, there needs to be a decision making process established for the reference level, a periodic review of these levels (say every 3 years), and an approach to address appeals from market participants. The IESO may wish to consider using an independent third party for the design of the reference level methodology and the negotiation of the finalization of these reference levels with market participants.	The IESO has developed a proposal for an independent review process of reference levels and quantities. This proposal will be shared with stakeholders later in 2020.
172	Market Power Mitigation	OPG	[...] The IESO should provide an example of how the proposed reference level curve would be determined, implemented and enforced. [...] [...] The MPM detailed design does not provide a methodology for determining what is included in opportunity costs.[...] OPG submits that risk premiums should also be recognized as a legitimate cost in reference level pricing. [...].	Reference levels will reflect actual short-run marginal costs of a resource. For resources where the rate at which costs are incurred does not increase in production, reference levels will have a single step. For resources where the rate at which costs are incurred increases in production, the reference level curve will have multiple steps to reflect that relationship. More information on reference levels can be found in the reference level written guide. That document outlines the draft methodology for determining reference levels for each technology type, including the methodology for accounting for opportunity costs for energy limited resources. This methodology will be discussed in detail during the reference level engagements.
173	Market Power Mitigation	OPG	In paragraph #2 of the section on Reference Levels, the IESO includes a statement that the gross revenue charge (GRC) will be considered in setting reference levels for hydroelectric resources - this is only one element impacting hydroelectric offers. Other factors, including opportunity costs and risk premiums for hydroelectric with limited water supply, require significant consideration. [...] OPG would 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 [...]	Market participants should refer to the reference level written guide for more information regarding the gross revenue charge. The written guide was included as pre-reading material for the reference level discussion on August 27th and the technology-specific reference level discussions on November 26th and 27th. The methodology for determining reference levels for each technology type is found in that document, including the methodology for accounting for opportunity costs for energy limited resources. This methodology will be discussed in detail during the reference level engagement.

ID	Design Document	Stakeholder	Feedback	IESO Response
175	Market Power Mitigation	OPG	Section 3.14.2 of Market Power Mitigation (MPM) detailed design states reference quantities will be established following the approaches outlined in the Reliability Outlook Methodology, unless these approaches do not fully account for the specific operational characteristics of a resource. Please specify what aspect of the Reliability Outlook Methodology will be applied as OPG is concerned that this approach does not account for the unique characteristics of hydroelectric resources. [...] As an alternative approach, OPG suggests registering a new parameter called "minimum head based capability" for each hydroelectric generating which can then be used to calculate a physical withholding reference: Physical Withholding Reference Level (single unit) = Max ((min head based capability - derates/outages), 0) The above calculation could then be summed for resources with more than one unit. Hydroelectric units would register this new parameter as part of facility registration. "	The IESO released its approach on hydroelectric reference quantities in the pre-reading material to the Reference Levels and Reference Quantities stakeholder engagement held on August 27, 2020. The IESO looks forward to discussing these issues as part of the technology-specific reference level and quantity consultations.
178	Market Power Mitigation	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 appear to 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 many of these thresholds are based on US jurisdictional review. Further this value should be reviewed by the IESO on a periodic basis (say 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 MRP go-live. Any alterations required to better ensure it is supporting efficient market outcomes will be made through the Market Rule amendment process.

ID	Design Document	Stakeholder	Feedback	IESO Response
179	Market Power Mitigation	OPG	In Table 3-7, Conduct Thresholds for Impact Testing in BCA, the detailed design states for energy offers: "Offer price is greater than either 200% or $100/MWh above reference level value; offers below $25/MWh are excluded from economic withholding tests." It is important to note that both NYISO and MISO use thresholds of 300%. OPG proposes the IESO use a 300% threshold, which would be in line with neighbouring US jurisdictions. During the September 27th Technical Session for Economic Withholding, the IESO stated they intended to use thresholds that were consistent with other markets. Where thresholds differ from other markets, such as this one, the IESO responded that it was based on feedback from speaking with other jurisdictions in what they would change to redesign the threshold value. [...] [...] Post implementation, OPG would support a review of these thresholds and a change in this value, if these thresholds are deemed to be ineffective through the appropriate channels. The following change is recommended to the detailed design document: "Offer price is greater than either 300% or $100/MWh above reference level value; offers below $35/MWh are excluded from economic withholding tests."	The IESO will change the energy offer conduct thresholds in Sections 3.6.1.2 and 3.6.1.3 from 200% to 300%. This change will better align the mitigation design with values that have been used successfully in other jurisdictions. The IESO will observe the performance of the mitigation framework on an ongoing basis to assess its performance.
181	Market Power Mitigation	OPG	Please clarify whether the conduct and impact thresholds defined in Tables 3.5 to 3.27 will be the same in both the day-ahead and real time markets? OPG suggests different and larger thresholds be used for day ahead as compared to real-time given the larger uncertainty of fuel supply (water) for hydroelectric resources in the day ahead timeframe. In the absence of different thresholds, OPG proposes the IESO include weather/inflow related risk premiums in the costs and quantities included in reference levels. OPG remains concerned the thresholds are being set by the IESO prior to reference level negotiations with market participants. [...]	Conduct and impact thresholds are the same for the day-ahead and real-time markets. Market participants should refer to the reference level and reference quantities written guide for more information. The methodology for determining reference levels for each technology is found in that document. These methodologies, including how opportunity costs of energy limited resources will be determined, will be discussed in detail during the reference level engagement.
182	Market Power Mitigation	OPG	OPG is concerned the 0 MW MIN area constraint threshold is too low and could result in over testing. OPG requests the IESO provide rationale for a 0 MW MIN area constraint and suggests using a higher value consistent with other deadbands used in the current market, such as the ADE deadband of 2% or 10 MW. In this case, 2% of the total market OR would be ~30 MW, which is likely too high under Local Market Power constraints leading to OPG's recommendation to use a 10 MW MIN area constraint threshold.	Local minimum operating reserve requirements can significantly restrict competition in a given area. Therefore, relatively stringent thresholds are appropriate to discourage physical withholding and support efficient market outcomes. The value of the ADE dead band is not relevant for consideration of the condition for testing for local market power for operating reserve price impact.

ID	Design Document	Stakeholder	Feedback	IESO Response
184	Market Power Mitigation	OPG	OPG believes Section 3.8 is incomplete and the IESO should incorporate Market Settlements DES-28 Section 3.13.1 Make-Whole Payment Impact Test into this design document. Each type of make-whole payment requires its own impact test threshold and the one size threshold does not fit every make-whole payment. [...] [...] OPG further notes that DES-28 Section 3.13.1 states: "When a resource meets the conditions to carry out a make-whole payment mitigation impact test, the IESO will determine what the settlement amount would have been, if the dispatch data had been subject to mitigation based on the set of conduct and impact thresholds that apply to the most restrictive constrained area. The most restrictive set of thresholds for the dispatch data will be determined over the period that the settlement amount is calculated. Therefore, if the settlement amount is calculated over multiple hours, the hour with the most restrictive set of thresholds will determine the set of thresholds used in all hours of the calculation." [...] It seems reasonable during settlement mitigation each of these hours remains independent prior to being summed to a total make-whole payment. [...] OPG recommends the IESO define a make-whole payment impact test for each of the make-whole payment amounts which sets the thresholds as hourly or commitment based, and considers that DAM_MWP and RT-MWP are components of DAM_GOG and RT-GOG. Further Section 3.8 needs further stakeholder discussion and should be subject to a technical discussion due to the complexity of its application.	Each MWP will be calculated as described in the Market Settlements detailed design document. The make-whole payment impact test is one part of determining a given make-whole payment. Using the most restrictive condition that applies over the commitment period for the Real-Time Generator Offer Guarantee and the Day-Ahead Generator Offer Guarantee is an important feature of the design. The importance comes from the fact that the calculation engine must commit a NQS resource for a contiguous block of hours equal to the resource's minimum generation block run time (MGBRT). As a result, when a resource has market power in one hour of the commitment, it may have the ability to exercise that market power in an earlier or later hour of the commitment, or in its start-up offer.
185	Market Power Mitigation	OPG	Section 3.8 should explicitly remove Day Ahead Balancing Credits (DAM_BC) from make-whole payment mitigation. [...] Imposing make-whole payment mitigation on a settlement amount that is designed to compensate a market participant for financial losses incurred after following a reliability dispatch is not reasonable. Please provide an example on when it would be appropriate to mitigate the DAM_BC make-whole payment.	Market Power Mitigation will not affect the DAM balancing credit (DAM_BC) for domestic resources. This is because the DAM_BC is not based on offers and so cannot change as a result of mitigation. Reliability constraints will be tested for make-whole payment impact.

ID	Design Document	Stakeholder	Feedback	IESO Response
186	Market Power Mitigation	OPG	For make-whole payments in Section 3.8.1, the impact thresholds appear to be the same for NCAs/DCAs (Table 3-16), BCAs (Table 3-18), and Global Market Power (Table 3-22). The thresholds for BCAs and Global Market Power should be higher than NCAs/DCAs as BCAs and Global Market Power are more competitive areas. OPG proposes the thresholds for BCA and Global Market Power be increased from 10% to 50% higher than the make-whole payment calculated using the reference level values. This approach considers that in Table 3-9 the conduct thresholds for Global Market Power are 100% of the reference levels for both Speed-no-load and Start-up costs indicating a more competitive area then the NCA/DCA, however, recognizing the calculation of Make-Whole Payments is complex and uses both components, a 50% threshold on make-whole payments is more logical than suggesting 100%.	The IESO will increase MWP impact thresholds for broad constrained area (BCA) and Global Market Power in Sections 3.8.2 and 3.8.3 to 20%. This change will better align the market power mitigation framework with the MPM guideline that as competition becomes more restricted, MPM thresholds should be less permissive. Price impact thresholds are generally higher than make-whole payment thresholds. Higher price impact thresholds help to avoid unnecessary intervention with market price determinations unless there is a material price impact due to an exercise of market power.
187	Market Power Mitigation	OPG	Section 3.8.2 bullets states: "- An NQS resource was committed, which would otherwise receive a make-whole payment, and has a positive congestion component greater than $0/MWh on any binding constraint that was not an NCA or DCA constraint; or - An NQS resource was committed, which would otherwise receive a make-whole payment, and has a GSF greater than 0.02 on an active constraint that was not an NCA or DCA constraint and which would have been binding or been violated but for the commitment of the resource" More information about IESO's rationale for using a positive congestion value set at any number greater than $0/MWh is required. The IESO should increase the positive congestion component to at least greater than $2/MWh. The use of $0/MWh may trigger time consuming and costly reviews by the Market Participant and the IESO when positive congestion is as little as $0.01.	The $0/MWh value acts as an indicator that communicates whether the resource has an impact on a transmission constraint. It is not a measure of materiality. Setting this threshold to $0/MWh is intended to identify any resource that could impact the constraint. To use $2/MWh as the threshold value would inappropriately rule out some occasions when a resource was committed in order to resolve that constraint. An NQS resource needed to resolve a transmission constraint could exercise market power by offering very high commitment costs. These commitment costs may not be assessed with a threshold greater than $0/MWh as the commitment costs are not captured in the cost (shadow price) of the constraint.

ID	Design Document	Stakeholder	Feedback	IESO Response
188	Market Power Mitigation	OPG	OPG is concerned the IESO has not considered unit status in the development of the pre-testing criteria for NQS unit's make-whole payments of $10,000. This oversight may cause systemic over-testing of resources simply due to the unit status being warm or cold. Instead the pre-testing criteria should use the reference level start-up cost of the unit when assessing whether to proceed with conduct and impact testing. For example, if a unit has a reference level start up cost of $20,000 then a make-whole payment of $20,000 should not trigger the testing criteria. [...]	The start-up reference level of the resource will account for the thermal state for MWP testing. A cold start reference level will be likely higher than a hot start reference level due to increased fuel consumption associated with a cold start. The methodology described in the feedback is essentially an additional impact test for make-whole payments. The impact test will only occur if the conditions for make-whole payment testing were met and if the conduct test was failed for a particular resource. The IESO will change the value in the second condition in Section 3.8.4 from $10,000 to $15,000. This change will improve the alignment of the mitigation design to the mitigation guidelines by being more reflective of Ontario-specific circumstances.
189	Market Power Mitigation	OPG	The 1x, 2x, 3x persistence multiplier progression from Table 3-29 may be overly punitive - the NYISO uses a less punitive progression of 1x ,1x , 2x, 3x. Further OPG would like additional details on how these multipliers are applied in terms of timing. For example, can multiple infractions on a single day lead to the max multiplier penalty? Or must the infractions occur on separate days for the multiplier to progress? There is an existing MACD process to manage these types of infractions by market participants and this process does not need to be duplicated by the IESO. Will the IESO penalties replace MACD compliance or will it be in addition to MACD compliance?	The persistence multiplier provides an increasing disincentive for market participants exercising market power via physical withholding. The New York Independent System Operator (NYISO) multiplier referred to applies to financial sanctions for a range of findings. It is not solely concerned with findings of physical withholding. Regarding timing, there can only be one instance of physical withholding per day per resource. A market control entity with more than one resource could have multiple instances per day. Each instance will contribute to the multiplier for future assessments. As stated in Section 2.2 of the mitigation detailed design document, the IESO's review for market power mitigation, including testing and any related step taken by the IESO, will not constitute a review for compliance with any market rule.

ID	Design Document	Stakeholder	Feedback	IESO Response
191	Market Power Mitigation	OPG	In Table 3-30 for Physical Withholding of Global (OR), the first bullet states: " - Submitting operating reserve offers of quantities that are lower than either 10% or 100 MW below a resource's reference quantity." The above thresholds are too narrow for small resources. [...] OPG proposes the IESO should reword the bullet to: "Submitting operating reserve offers of quantities that are lower than the greater of " The thresholds should be set higher to reflect this is a global market power assessment which would result in having a large number of resources impacted. [...] Further, OPG recommends the IESO revisit all of the terminology used in setting all conduct and impact thresholds to use terms explicitly stating whether it is the greater of or the lesser of prior to engaging in reference quantity negotiations with market participants. The 2nd bullet from Table 3-30 states: " - For at least two resources from one market control entity, submitting operating reserve offers of quantities that are in the aggregate, lower than either 5% or 200 MW below the resources' aggregate reference quantities." OPG proposes the IESO consider the number of resources that will be in the global market constrained area (potentially all Ontario generators) and only use the percentage threshold. [...]	The IESO will make the following change: "Submitting operating reserve offer quantities below 10% of the reference quantity (minimum being 5 MWs to a maximum of 100 MWs) or 100 MW below a resource's reference quantity." Regarding changing the language from "less of" to "the greater of" the IESO will keep the existing language. The intent of using a % and MW threshold is to control for large resources where the % amount would be large. For these resources, the MW amount means that the conduct threshold will not grow too large in MW terms. To modify the language so that the threshold is the "greater" of the % or MW threshold would allow all resources to physically withhold at least 200 MWs and to allow large resources to withhold even more. The IESO will clarify the language in the design document to make explicit in each case whether it is the lesser of or greater of for each conduct test. Regarding the request to remove the 200 MW aggregate reference quantity - the IESO will continue to use this value. It is consistent with other United States jurisdictions that have higher installed capacities than Ontario.
192	Market Power Mitigation	OPG	For market transparency, the IESO should provide notification at least 14-days in advance for planned transmission outages that will trigger a DCA. [...] In addition the criteria to trigger DCAs should be reviewed by the IESO, and provided to market participants similar to Market Participant Confidential 'Outage Planning Guideline Reports'.	The details on publication of an upcoming DCA designation will be found in the relevant market manual and market rule documentation. The IESO understands the issue and agrees that this directly relates to transparency. Understanding at what stage an upcoming outage is certain enough to warrant notice of a DCA is important to come to determine for this topic. These process-related issues will be addressed in the process of drafting the relevant market manuals and market rules.

ID	Design Document	Stakeholder	Feedback	IESO Response
193	Market Power Mitigation	OPG	OPG recommends that IESO publish standardized reports on upcoming NCA/DCA/BCA/Global Market Power/Uncompetitive Interties prior to Day Ahead Market submission window opening (i.e. prior to 06:00 EPT day ahead). This publication timeframe allows market participants sufficient time to adjust their day-ahead offers. If a new constraint designation occurs due to forced outages in real-time, OPG proposes the IESO allow market participants to revise offers including opening the mandatory window. This proposal will mitigate the impact of unplanned transmission conditions on generators.	DCA, NCA and uncompetitive intertie designations will be posted on the IESO website according to the timelines found in the market power mitigation detailed design document. A new DCA or NCA designation will not occur in real-time of the day-at hand. BCA and global market power conditions are determined as part of the process of determining schedules and prices during dispatch. Therefore it is not possible to publish a report identifying them in advance.
194	Market Power Mitigation	OPG	For market transparency, OPG suggests the IESO publish private reports at the end of each dispatch interval that flag which dispatches were the result of an IESO manual constraint. This report should contain the manual constraint types to determine which constraints are excluded from mitigation. [...] [...]	The IESO will provide information about when a resource is dispatched due to a manual constraint and when a resource meets the condition for a reliability constraint for settlement mitigation. Determining the solution to provide this information will be carried out during implementation.
195	Market Power Mitigation	OPG	In Section 3.12.5, please clarify the IESO's timeframe for publishing the designation of uncompetitive interties. The IESO should use similar publication criteria as used with NCA designation. At minimum, the IESO should publish in advance of the Day Ahead submission window at or before 06:00 EPT.	The IESO will reflect this suggested change in Section 3.12.5 of V2.0 of the document. The change will improve the alignment of the mitigation design with the MRP principles and the MPM guidelines as described in the Single Schedule Market (SSM) high level design document. This additional transparency will aid market participants' understanding of the MPM framework without increasing the ability for participants to exercise market power.
196	Market Power Mitigation	OPG	The comment in the final bullet of Section 3.12.5 should be more clearly defined and not subjective: "An intertie where the IESO finds grounds to believe that effective competition for the supply of imports or demand for exports is or is expected to be restricted."	As described in Section 3.12.5 the IESO will use a threshold value of 90% of trade on a given intertie to designate an intertie as uncompetitive. In addition to this quantitative threshold, the IESO will also have the ability to assess whether competition on a given intertie is, or is expected to be, restricted. This is necessary to safeguard against circumvention of the 90% threshold by a participant who controls trade on the intertie in question.
197	Market Power Mitigation	OPG	[...] A risk premium is necessary to allow a market participant to offer flexibility in real time above the day-ahead schedule taking into account the need for physical schedule changes in future hours for both energy and operating reserve.	The methodology for determining reference levels, including how to account for opportunity costs for energy limited resources, is being discussed in the reference level implementation stakeholder engagement.

ID	Design Document	Stakeholder	Feedback	IESO Response
198	Market Power Mitigation	OPG	OPG would appreciate further details on how the IESO intends to apply Administrative Pricing principles (Market Manual 4.3, Section 9) to LMPs (as opposed to the current uniform pricing) in the event reference prices are determined to be incorrect. This is important as the two-day timeline associated with the IESO issuing administrative pricing means participants must have the opportunity to appeal its issued reference price within the two days. The design states that if a participant disagrees with the IESO determined reference price and the price is not changed prior to dispatch, the current Notice of Disagreement (NOD) process will be available to that participant for recourse. As the NOD process cannot be initiated until the preliminary settlement statement is received (ten business days after the fact), the IESO will be unable to administer prices with the correct reference prices. OPG believes a more expeditious process should be available for market participants to appeal reference prices prior to administrative pricing deadlines.	If a market participant updates a reference level via a Notice of Disagreement, the IESO will recalculate MWPs for the resource. It is not implementable for the IESO to re-settle the market in such a case. The IESO has developed a proposal for an independent review process of reference levels and quantities. This proposal will be shared with stakeholders later in 2020.
201	Market Power Mitigation	OPG	In the final bullet on Page 55 the design states the following: "the market participant notifies the IESO of an increase or a decrease in its initially submitted costs. Market participants shall inform the IESO if their initially submitted short-run marginal costs – excluding fuel and opportunity costs – decrease no later than five business days following the decrease in costs coming into effect." OPG recommends the IESO and market participants explicitly define which cost parameters will be excluded.[...]	The IESO will remove the obligation to notify the IESO if costs will be lower than is reflected in the reference level. This obligation is no longer necessary because of the approach that the IESO is taking to determine financial reference levels that relies in part on historical costs incurred by a resource. The details of this approach are found in the reference level implementation stakeholder engagement material.
202	Market Power Mitigation	OPG	In section 3.13.1.1, the design states: "If a resource has not established an operating reserve reference level, the IESO will use a default reference level of $0.10/MW." A default reference level for OR should only be applied in the event a market participant is in agreement. A backstop default reference level, may not yield a collaborative outcome on reference levels.	For clarity, when a market participant submits a request for an energy or operating reserve reference level equal to or lower than $0.10/MW, no supporting materials are required to be submitted. The mitigation design document will be updated to reflect this clarification.
203	Market Power Mitigation	OPG	In section 3.13.1.1, the design states: "On a daily basis, the IESO will populate the values for each of the variables in each equation and the reference level values will be determined for a particular dispatch day for every applicable resource. The data that the IESO will use to populate values for each variable will depend on the variable. For example, natural gas prices would be used to populate values for energy reference levels for gas-fired resources." The IESO should develop a process that allows market participants to view and revise these variables during the market submission timeline. [...]	The IESO will describe the process and acceptable documentation for submitting change requests in the appropriate Market Rules and Market Manuals.

ID	Design Document	Stakeholder	Feedback	IESO Response
205	Market Power Mitigation	OPG	In paragraph #4 of this section (3.13.1) on Page 58 it is stated that: "The IESO will use the least expensive fuel type among the registered primary and secondary fuel types for a resource's reference level for the timeframe when it tests a submitted offer for market power. Market participants can request the IESO to change this default fuel type selection if the least expensive fuel (in $/MWh), as flagged by the market participant and approved by the IESO, is unavailable or not preferred because of an acceptable reason for the specific subset of hours during the trading day." [...] OPG recommends further discussion between market participants and IESO as part of the reference level negotiation for energy offer curves to account for situations where the energy offer curves of the two fuels cross. [...] There should be a method for market participants to submit outages for specific 'fuel types', without impacting the availability of the resource, as they would be available on the alternative fuel. [...]	Market participants should refer to the reference level written guide for more information. The methodology for determining reference levels for each technology is found in that document, including the methodology for determining operating reserve reference levels. This methodology will be discussed in detail during the reference level engagement. The IESO looks forward to discussing this issue as part of technology-specific consultations. Section 3.13.1.2 of the market power mitigation design document describes the process for dual fuel resources to indicate unavailability of the lower cost fuel type.
207	Market Power Mitigation	OPG	In the section on Settlement Process for Mitigating Dual Fuel Resources, the design states: "After the market participant places a request to use the higher-cost fuel in either of the timeframes, they must provide evidence to the IESO that the higher-cost fuel was used. This evidence must be provided within two business days after the trading day in which the higher-cost fuel was used. The settlement process should provide at least one week for market participants to provide information on expenses incurred. It can take more than two day for market participants for some expenses to be incurred. [...] This Settlement Process would not be required if the IESO in collaboration with market participants develop reference level curves that capture the unique challenges of dual-fueled resources. The IESO should enhance its tools to support reporting of fuel availability either through the outage process or the offer submission process. [...] If the IESO is unable to enhance their processes, OPG suggests the settlement process should use timelines similar to the current RT-GCG program which allows expense information to be submitted within a reasonable number of days after the fact.	For clarity, the design indicates that that the market participant must provide evidence that the higher-cost fuel was used, not evidence of the costs of the higher cost fuel. The detailed design document addresses availability of lower cost fuel types in Section 3.13.1.2 - sub-section titled "Dual-Fuel Resource Treatment." That section describes the process that market participants can use to communicate to the IESO that the more expensive fuel-type must be used on a given day.

ID	Design Document	Stakeholder	Feedback	IESO Response
208	Market Power Mitigation	OPG	The fourth paragraph of Section 3.13.2 the design states: "In the event that a market participant makes changes to a resource that impacts the operational characteristics described by a non-financial reference level, the market participant must update the registered value of the relevant non-financial reference level no later than five business days following such a change." Changes to non-financial reference levels should be made following completion of testing and commissioning rather than five days after the operational change is made to registration data. [...]	The IESO agrees with this suggestion and will update the language in Section 3.13.2 accordingly.
209	Market Power Mitigation	OPG	This IESO's strategy of establishing reference levels for non-financial data is not suited to hydroelectric. [...] OPG proposes that during the reference level negotiations a process is established that will allow daily inputs by market participants to be used in the reference level curves for energy and operating reserve.	The IESO looks forward to discussing these and other considerations as part of the technology-specific reference level consultations. Please note that non-financial reference levels have reference level thresholds to allow for flexibility in operational parameter variations.
210	Market Power Mitigation	OPG	[...] The last paragraph of Section 3.14.2 (reproduced below) implies that the IESO will make final decisions on reference quantities without approval by market participants, which concerns OPG. OPG suggests a third party mediator or arbitrator may be required to reach consensus on decisions regarding reference levels. In addition, a dispute resolution process should be developed. [...]	The IESO has developed a proposal for an independent review process of reference levels and quantities. This proposal will be shared with stakeholders later in 2020.
212	Market Power Mitigation	OPG	In section 3.14.2, the design states: "The reference quantity for suppliers of operating reserve will be based on the operational capability of the resource. Operational restrictions that prevent a supplier of operating reserve from providing incremental energy can be reflected in their reference quantity." The IESO should enhance outage reporting tools to allow outages or derates to Operating Reserve capability. OPG notes that Ancillary Out of Service (ASPOOS) slips are informational and OPG does not believe they transfer into the current calculation engines. In the current market, outages or derates impact both energy and OR. Hydroelectric stations face water management and physical constraints that allow energy production but make stations unavailable for OR.	The IESO is open to the idea of using ancillary out of service slips to inform operating reserve reference quantities. As the physical withholding framework will assess the withholding of available supply, this information seems relevant in the determination of those quantities. This information does not need to be provided directly to the calculation engines as the reference quantity information will be informed with information from the outage management system. The IESO encourages market participants to discuss reference quantities during the reference level engagement.

ID	Design Document	Stakeholder	Feedback	IESO Response
214	Market Power Mitigation	OPG	Section 3.15.1 states: "A market participant will be able to submit an ex-post cost recovery request for a resource when: -The IESO has applied market power mitigation to this resource for all or part of one or more trading days; and - The market participant believes that the reference level for a financial parameter used during the mitigation process did not reflect the allowable short-run marginal costs the market participant incurred." OPG would like the IESO to provide a firm 5 day commitment to respond to these eligibility requests following submission by a market participants.	These requests will be carried out via the existing Notice of Disagreement process. MRP does not contemplate any changes to the timing requirements around the Notice of Disagreement process. The IESO will continue to deal with Notices of Disagreements according to the timelines of the relevant market rules and manuals.
276	Market Power Mitigation	Power Advisory	Take into account Ontario's specific and unique structural differences compared to the U.S. wholesale electricity markets in the design and rules for a market power mitigation framework for the IAM. o This should result in a more stream-lined and efficient framework to mitigate for physical withholding, given energy supply incentives within OPG's forthcoming 'must-offer' supply obligations and contracts for nearly all other generators. This will ensure this aspect of market power mitigation will not 'over-mitigate'. o Considering well documented anti-competitive behaviour from demand-side MPs within the IAM, a mitigation framework for demand-side resources should be developed. This helps to unsure that market power mitigation will not be 'under-mitigated'. o Especially for sub-zones in the Northwest and Northeast zones, the combination of surplus baseload generation (SBG), 'out of market' incentives and drivers from contracts and rate-regulated frameworks for most generators located in these sub-zones, combined with the potential for offer behaviour from some resources that may change resulting from potential prolonged and very low Locational Marginal Prices (LMPs), a mitigation framework to address predatory pricing and price suppression will likely be needed. This will also help to ensure that market power mitigation will not be 'under-mitigated'.	The MPM design is intended to prevent exercises of market power by any registered market participant. The existence of other obligations outside of the IESO-administered markets does not alter the intention of the design. To remove mitigation for physical withholding under the MPM design would allow exercises of market power to go unchecked. As stated in Section 2.2.4 of the detailed design document: in the event that demand-side market participants receive payments for reducing or avoiding consumption, this design should be amended so that they are tested for market power similar to other suppliers of energy. The settlement price floor included in the MRP design reduces the potential impact of extreme negative prices below competitive levels on market outcomes.

ID	Design Document	Stakeholder	Feedback	IESO Response
277	Market Power Mitigation	Power Advisory	Review the efficacy and practicality of the proposed global market power mitigation framework, as incremental imports may not be good indicators of whether global market power is being exercised and therefore need to be mitigated. However, if incremental imports are to be the framework to assess and mitigate global market power, this framework needs to be expanded to include all of Ontario's interconnections.	Global market power is contingent on the availability of incremental imports from neighbouring jurisdictions with competitive wholesale markets. Such imports can act as competition with a supplier(s) who may otherwise have market power in the province. As stated in Section 3.6.1.3, the following criteria were used to determine the Global Market Power Reference Interties: -the intertie connects Ontario to another wholesale electricity market; and -the intertie is able to provide an effective competitive discipline for market participant behaviour. Based on the above criteria, the IESO has determined that the New York (NYISO) and Michigan (MISO) interties satisfy the criteria listed above. Use of these two interties is solely to determine when global market power could exist for internal resources. As a reminder, market power mitigation does apply to all interties that are designated as uncompetitive, as specified in Section 3.10.
278	Market Power Mitigation	Power Advisory	Because the proposed Conduct & Impact Test market power mitigation framework will be an impactful and new feature within the IAM, with potential results that could alter the economics of applicable MPs (e.g., generators inside load pockets), IESO should establish a standing market power mitigation stakeholder engagement – not just a lesser scope stakeholder engagement only relating to establishment of reference levels and reference quantities, as announced during IESO's July 24, 2020 MRP update presentation.	Thank you for your feedback. The IESO will take this input into consideration when determining the appropriate future engagement for MRP.
279	Market Power Mitigation	Power Advisory	Ontario Power Generation Market Dominance [...] considering OPG's dominant market share coupled with the forthcoming 'must-offer' supply obligation, the Consortium is of the opinion that substantial potential to exercise market power within the IAM may then be addressed. However, a market power mitigation framework within the IAM will still be required, but IESO should factor in potential implications of OPG's forthcoming 'must-offer' supply obligations when designing the market power mitigation framework – in particular the physical withholding framework within the proposed Conduct & Impact Test.	The MPM design is intended to prevent exercises of market power by any registered market participant. The mitigation design includes assessments of occasions when competition is restricted as well as when a market participant is found to have exercised market power. The existence of other obligations outside of the IESO-administered markets does not alter the intention of the design.

ID	Design Document	Stakeholder	Feedback	IESO Response
280	Market Power Mitigation	Power Advisory	[...] Demand-Side Mitigation [...] The above example clearly shows the need for IESO to explore an explicit demand-side mitigation framework within the IAM, for inclusion within MRP design and therefore within subsequent versions of Market Power Mitigation Detailed Design. It is acknowledged that under Section 2.2.4 of the draft Market Power Mitigation Detailed Design Issue 1.0 regarding dispatchable loads and hourly demand response resources that IESO has stated "… in the event that these demand-side market participants receive payments for reducing or avoiding consumption, this design [market power mitigation] should be amended so that they are tested for market power similar to other suppliers of energy". Considering the history of anti-competitive behaviour by some dispatchable loads, not only by the OR example above but also including gaming CMSC payments and at times exercising local market power10, the Consortium believes there is sufficient historical evidence and therefore need to develop a demand-side mitigation framework within MRP.	Dispatchable loads are suppliers of operating reserve and will be subject to market power mitigation for operating reserve. This will apply for economic withholding (price-impact and make-whole payment impact) and physical withholding (price-impact). As stated in Section 2.2.4 of the detailed design document: in the event that these demand-side market participants receive payments for reducing or avoiding consumption, this design should be amended so that they are tested for market power similar to other suppliers of energy.
281	Market Power Mitigation	Power Advisory	Predatory Pricing and Price Suppression Mitigation Ontario has a set of unique and specific factors that enable potential anti-competitive behaviour through predatory pricing – unilaterally exercising a dominant market position to lower and suppress prices below competitive levels in order to create barriers to participate within the IAM (i.e., causing some resources to not be economically dispatched to supply energy and/or OR). [...] Again, the same rationale is analogous and applicable to the need to address similar dynamics within the IAM, as contemplated under the MRP design – specifically through market power mitigation.	The settlement price floor included in the MRP design reduces the potential impact of extreme negative prices below competitive levels on market outcomes.
284	Market Power Mitigation	Power Advisory	Section 3.4.1 – The Mitigation Process This section provides a useful overview of the proposed market power mitigation process. However, it is not a complete process, since steps for MPs to dispute IESO's application and results of market power mitigation needs to be included along with additional recourse MPs may exercise in addition to utilizing dispute mechanisms.	The IESO has developed a proposal for an independent review process of reference levels and quantities. This proposal will be shared with stakeholders later in 2020.

Market Settlement

ID	Design Document	Stakeholder	Feedback	IESO Response
429	Market Settlement	Capital Power	Pseudo Units may have different MLP levels depending on the configuration they are scheduled in. Flexibility will need to be built into this design element. (see Capital Power Pseudo unit submission March 2020)	The linear PSU model cannot recognize differences in non-linear operating characteristics under different configurations. To address this limitation would require an overhaul of the PSU model with a different way of modelling combined cycle facilities. Market participants have flexibility to submit energy and reserve offers and dispatch data that best reflects the physical capabilities for their resources' anticipated configuration.
430	Market Settlement	Capital Power	The selection of Single Cycle mode should be available to MPs in DAM, PD and RTM. A loss of system flexibility will result otherwise. The IESO May consider allowing units to register as PSU and Physical or add additional data inputs.	With the PSU model, market participants will have the ability to switch between single and combined cycle modes for new commitments, provided the PSU is offline and does not have a future commitment on the current dispatch day. While PSU may physically be able to switch between single and combined cycle modes while generating, calculation engines using pseudo units cannot recognize the transition intra day to switch and dispatch the new configuration correctly. The PSU model assumes a 1x1 configuration when the PSU is evaluated for commitment. Therefore, it cannot recognize differences in MLP due to different operational configurations. In situations where PSU are scheduled in a configuration that requires a higher MLP than is reflected in dispatch data, market participants have the ability to request a minimum generation constraint to prevent equipment damage (SEAL). To address these two limitations would require an overhaul of the PSU model with a different way of modelling combined cycle facilities.
434	Market Settlement	Capital Power	Operating offer curves should not automatically occupy the dispatchable and duct firing regions. Duct firing regions do not operate the same as the dispatchable region for some assets, and OR offering in this region may need to be restricted.	A new registration parameter will be included for market participants to declare whether 10-minute reserve can be scheduled in the duct firing range. The registered option for 10-minute reserve in duct firing mode will be used to inform the calculations engine whether or not 10-minute reserve can be scheduled for the PSU resource. The Facility Registration and Calculation Engine design documents will be updated to reflect this design change.

ID	Design Document	Stakeholder	Feedback	IESO Response
438	Market Settlement	Capital Power	There appears to potentially be a lack of fairness relating to the formulation of DAM_BC, as this section states that "… it [DAM_BC] does not provide a guarantee of the operating profit." If DAM_BC will not ensure operating profit, then this credit payment appears on initial review as being less than what it needs to be. If the IESO determines there is a reliability need, the participant should be made whole to the operating profit they lost as a result. This credit should also be expanded to include instances where the IESO commits a generator to run beyond their original DAM schedule and dispatch them offline without enough time to meet a second DAM schedule in the dispatch day.	The DAM_BC is not intended to provide a guarantee for the operating profit in the real-time market. The DAM_BC is designed to align with two-settlement such that it protects the resource from financial loss due to real-time buy-back when dispatched off for reliability reasons. If a resource is dispatch off for a reliability need, both the DAM Make-Whole Payment and the DAM_BC will ensure that the market participant is not worse off by following the IESO's dispatch instructions. The IESO will not dispatch a generation unit such that it would not be able to meet a future commitment, unless there is a reliability need. As described in Grid and Market Operations Section 3.7.2.1, the IESO will either keep the generation unit online and bridge the two commitments or the resource will be dispatched offline to respect its minimum generation block down time. Therefore, the DAM_ BC does not need to be extended to cover these situations. Resources that are bridged between two-commitment periods are eligible for the Real-Time Generator Offer Guarantee and the Real-Time Make-Whole Payment for the bridged period.

Offers, Bids, and Data Inputs

ID	Design Document	Stakeholder	Feedback	IESO Response
487	Offers, Bids, and Data Inputs	AEMA	Advanced Energy Management Alliance ("AEMA") has become aware of a harmful design element that straddles several Detail Design documents recently posted. The DD documents referenced are "Offers, Bids and Data Inputs", "Market Settlements" and "Facility Registration". The element of concern is the relationship between "Hourly Demand Response" resources and "Price Responsive Loads". In the current framework Non-dispatchable ("ND") loads are permitted to participate as a virtual DR resource in an aggregated portfolio. Some customers opt to participate in this manner to reduce risk and maximize value. In the Facility Registration Detail Design Document Section 3.5.2 Load Facilities, under the heading "Virtual Hourly Demand Response Resources" it is stated "A virtual hourly demand response resource can continue to only be registered to fulfill a virtual demand response capacity obligation with non-dispatchable loads and/or virtual contributors that are not metered with the IESO. As with dispatchable loads today, a price responsive load will not be able to register as a contributor to a virtual hourly demand response resource." Price responsive loads ("PRL's") will be able to participate in the Day-ahead market and secure financially binding energy positions which is expected to deliver increased efficiencies to the market. They will continue to be non-dispatchable in Real Time, so ND Loads that choose to also be a price responsive load will not be able to continue the current option to participate in an aggregated portfolio. As the Capacity Market continues to evolve and forward delivery periods become more distant into the future and loads make commitments with their DR provider, they will limit their ability to opt to become PRL's for years. The IESO has indicated this is a tool limitation and is not a desired Market Design outcome. After discussions with other stakeholders, it is apparent this consequence was not identified during the review of the Facility Registration Detailed Design document. AEMA suggests the IESO reconsider this design element and present the issue to the broader stakeholder community for further discussion and possible solution.	The unique registration requirements provided to virtual Hourly Demand Response (HDR) in an aggregated portfolio for the purpose of the capacity market create problems for energy market tools to accurately account for a non-dispatchable load seeking to participate as a price-responsive load (PRL) in the energy market. Failing to properly do so would have adverse impacts to market settlement and demand forecasts. The IESO is considering what modifications are required to the registration of an aggregated portfolio within the capacity auction in order to facilitate participation as a PRL. The detailed design document will be revised to enable a contributor to a virtual HDR portfolio to participate as a PRL, conditional on those modifications made in the capacity market.

ID	Design Document	Stakeholder	Feedback	IESO Response
113	Offers, Bids, and Data Inputs	AMPCO	The description of the various penalty curves for OR would benefit from the addition of graphs to illustrate the interrelationship of the various product curves. Since it affects price it is of great interest to AMPCO members and we would like to understand it better. Additional stakeholder discussion in this area (including CAOR) is recommended.	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 implementation phase of the MRP. Constraint violation penalty curves for operating reserve will be used to set reserve shortage prices in the future market, replacing the current mechanism for reserve shortage pricing which includes the use of Control Action Operating Reserve (CAOR) offers. CAOR offers were intended to represent the historical price associated with a reserve shortfall when market resources are insufficient to meet those requirements. As the magnitude of the CAOR offer schedule increases, so does the operating reserve price. The constraint violation penalty curves for operating reserve in the future market will conceptually serve the same purpose as CAOR. Price points along the curve will gradually increase with the magnitude of the shortfall condition. Prices on the curve should not be excessively high for lower magnitude shortfalls nor excessively low for higher magnitude shortfalls.
441	Offers, Bids, and Data Inputs	Capital Power	In its current state, there is not enough information regarding CAOR offers to understand the impact to operating reserve market performance. Capital Power, therefore, request that the IESO provide more information regarding CAOR offers to determine the impact of replacing CAOR offers with a constraint violation penalty curve.	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 implementation phase of the MRP. Constraint violation penalty curves for operating reserve will be used to set reserve shortage prices in the future market, replacing the current mechanism for reserve shortage pricing which includes the use of Control Action Operating Reserve (CAOR) offers. CAOR offers were intended to represent the historical price associated with a reserve shortfall when market resources are insufficient to meet those requirements. As the magnitude of the CAOR offer schedule increases, so does the operating reserve price. The constraint violation penalty curves for operating reserve in the future market will conceptually serve the same purpose as CAOR. Price points along the curve will gradually increase with the magnitude of the shortfall condition. Prices on the curve should not be excessively high for lower magnitude shortfalls nor excessively low for higher magnitude shortfalls.

ID	Design Document	Stakeholder	Feedback	IESO Response
446	Offers, Bids, and Data Inputs	Capital Power	Capital power recognizes the potential benefits offered by the pseudo unit model. However, there are certain limitations with this model that limits its effectiveness. o The modelling of units as separate 1x1 configurations is problematic and may result in infeasible schedules, thereby impacting resource and system flexibility. The IESO should consider allowing resources to participate as individual Generation units or as Pseudo units to avoid the risk of reduced system flexibility. o Enhancing the dispatch tools for PSU's to recognize additional configurations would also enhance system flexibility and remove hurdles from NQS units considering registering as PSUs. (See Capital Power Pseudo Unit submission, March 2020)	Participants can choose whether they wish to participate as PSU or generation units during registration. Intra-day changes are not possible as the calculation engines are only capable of evaluating one resource type over the same look-ahead period. The linear PSU model cannot recognize differences in non-linear operating characteristics under different configurations. To address these PSU limitations, compliance aggregation is available to market participants. The ability to declare whether 10-minute reserve can be scheduled in the duct firing range will also be added to the design. In addition to this change, the "Steam Turbine 10-min Operating Reserve Contribution" parameter will be removed from the design. Through further design discussions, it became apparent that this parameter was not the right solution to address a number of concerns raised by stakeholders through their design feedback. Compliance aggregation in effect makes an 'infeasible' energy or reserve schedule on an individual resource 'feasible' as it allows the market participant to meet that schedule with the other resources at the facility. The registered option for 10-minute reserve in duct firing mode will be used to inform the calculations engines whether or not 10-minute reserve can be scheduled in the duct firing range for the PSU resource. The Facility Registration, Offers Bids and Data Inputs, Grid and Market Operations Integration and Calculation Engine design documents will be updated to reflect this design change.
447	Offers, Bids, and Data Inputs	Capital Power	The IESO should consider adding a Dispatch Data Parameter or allow OR to be offered on a voluntary basis. There are ranges of output that can not be utilized for the purpose of providing OR for some resources. Participants may be faced with a choice of an infeasible schedule or subjecting themselves to MPM.	Participation in the energy and operating reserve markets is voluntary and will continue to be voluntary in the future market. There is no requirement to offer operating reserve. Where a market participant does offer operating reserve, a new dispatch data parameter is not required. Market participants will be able to adjust the amount of operating reserve that they've offered to avoid being scheduled in ranges of output that they cannot provide. The methodology for physical withholding reference quantities is intended to reflect the available operating reserve that a resource is able to provide to the market. The consideration of what operating reserve is available is a topic for discussion through the active reference level engagements.

ID	Design Document	Stakeholder	Feedback	IESO Response
449	Offers, Bids, and Data Inputs	Capital Power	3.4.2 Start Up Offers • The detailed design document mentions in several places that the "Hot, Warm or Cold" status needs to be identified in the DAM submission. This presents a problem if the generator switches states partway through the day, or perhaps in the case of some generators, all three states could occur within 24 hours. This will need to be an hourly election allowing generators to select "Warm from HE 1-10, and Cold from HE 11-24" for example. There may be multiple cold start profiles for a Combined Cycle facility based on the number of hours it has been off-line. It is not clear if there is a way to account for this in the market design as proposed but should be included.	The DAM calculation engine design requires a market participant to select a single thermal state only for the purposes of allocating a single ramp up profile to minimum loading point for any given resource start in the DAM. Start-up offers, however, continue to be an hourly parameter as they currently are in the day-ahead commitment process. Market participants can submit different hourly start-up offers in the DAM under the selected thermal state. This allows the market participant to reflect lower start-up costs earlier in the day and higher start-up costs later in the day. The IESO will update the start-up offer section of the Offers, Bids and Data Inputs detailed design document to provide this clarity.
451	Offers, Bids, and Data Inputs	Capital Power	It is a concern that the new Hydroelectric dispatch parameters may incent uneconomic generation from the Hydro fleet at the expense of other asset classes. While Capital Power understands that this may be required from time to time due to environmental conditions, these should be limited to instances only when necessary. (see comments from Grid and Market Operations Integration 3.5.4.2)	The new hydroelectric dispatch data parameters may only be submitted to reflect operating restrictions that reasonably could be expected to prevent the resource from operating in a manner that would endanger the safety of any person, damage equipment, or violate any applicable law. Submissions that do not meet these conditions may be subject to non-compliance review.
452	Offers, Bids, and Data Inputs	Capital Power	Capital Power recommends adding a dispatch data field for a maximum loading point for providing OR. Otherwise a participant may unnecessarily be subject to Market Power Mitigation framework.	The calculation engines are unable to evaluate the complexity associated with a maximum loading point for operating reserve. Market participants will be able to adjust the amount of operating reserve that they've offered to avoid being scheduled in ranges of output that they cannot provide. The methodology for physical withholding reference quantities is intended to reflect the available operating reserve that a resource is able to provide to the market. The consideration of what operating reserve is available is a topic for discussion through the active reference level engagements.
453	Offers, Bids, and Data Inputs	Capital Power	The IESO should consider removing restrictions on a participant switching to Single Cycle Mode. It should not be solely at the IESO discretion as this will limit system flexibility and resources' ability to operate effectively. Generators may be able to start in a much quicker time frame in Single Cycle giving the system much needed flexibility. This recommendation may also remove a hurdle to electing to register as Pseudo Units.	With the PSU model, market participants will have the ability to switch between single and combined cycle modes for new commitments, provided the PSU is offline and does not have a future commitment on the current dispatch day. While PSU may physically be able to switch between single and combined cycle modes while generating, calculation engines using pseudo units cannot recognize the transition intra day to switch and dispatch the new configuration correctly. The PSU model assumes a 1x1 configuration when the PSU is evaluated for commitment. Therefore, it cannot recognize differences in MLP due to different operational configurations. In situations where PSU are scheduled in a configuration that requires a higher MLP than is reflected in dispatch data, market participants have the ability to request a minimum generation constraint to prevent equipment damage (SEAL). To address these two limitations would require an overhaul of the PSU model with a different way of modelling combined cycle facilities.

ID	Design Document	Stakeholder	Feedback	IESO Response
454	Offers, Bids, and Data Inputs	Capital Power	Pseudo units assess Generators in a 1x1 configuration only. Generators may have a different MLP for 1x1 vs 2x1. This will affect the economics of how a generator offers. The OR market will also be affected by this limitation. Capital Power recommends that these configurations be included as part of the PSU model.	The linear PSU model cannot recognize differences in non-linear operating characteristics under different configurations. To address this limitation would require an overhaul of the PSU model with a different way of modelling combined cycle facilities. Market participants have flexibility to submit energy and reserve offers and dispatch data that best reflects the physical capabilities for their resources' anticipated configuration.
461	Offers, Bids, and Data Inputs	Capital Power	Participants need to preserve existing flexibility to manage contract risk. The proposed design that applies to the offering of operating reserve restricts this ability.	Creating a physical withholding framework for operating reserve does not create an obligation under the market rules to offer operating reserve into the market. The Market Renewal team continues to coordinate, where necessary, with the Contract Management team on the detailed design. Neither team has identified any aspect of the physical withholding framework that would impair a market participant's ability to meet its contractual obligations.
463	Offers, Bids, and Data Inputs	Capital Power	OR supply associated with PSUs needs to respect multiple factors regarding allocation between CTs and STs: class of OR that can be supplied; operating range (e.g., duct firing) supplying OR; capabilities to supply OR at various operating ranges; and MPM (i.e., specifically IESO's application of physical withholding).	A "Steam Turbine 10-min Operating Reserve Contribution" parameter was proposed to address stakeholder concerns with the PSU model producing 10-min reserve schedules that a steam turbine would be incapable of meeting. Through further design discussions, it became apparent that this parameter was not the right solution to address a number of concerns raised by stakeholders through their design feedback. Additional concerns include 10-minute operating reserve schedules in the duct firing range and the accuracy of minimum loading point schedules for different combustion turbine and steam turbine configurations. Based on these considerations, the "Steam Turbine 10-min Operating Reserve Contribution" parameter will be removed from the design. Compliance aggregation is an alternate solution available to market participants, and a new registration parameter will be included for market participants to declare whether 10-minute reserve can be scheduled in the duct firing range. Compliance aggregation in effect makes an 'infeasible' energy or reserve schedule on an individual resource 'feasible' as it allows the market participant to meet that schedule with the other resources at the facility. The registered option for 10-minute reserve in duct firing mode will be used to inform the calculations engine whether or not 10-minute reserve can be scheduled for the PSU resource. The Facility Registration, Offers Bids and Data Inputs, Grid and Market Operations Integration and Calculation Engine design documents will be updated to reflect this design change. Market participants will be able to adjust the amount of operating reserve that they've offered to avoid being scheduled in ranges of output that they cannot provide. The methodology for physical withholding reference quantities is intended to reflect the available operating reserve that a resource is able to provide to the market. The consideration of what operating reserve is available is a topic for discussion through the active reference level engagements.

ID	Design Document	Stakeholder	Feedback	IESO Response
235	Offers, Bids, and Data Inputs	Emera Energy	Given that the duration of hot/warm and especially cold starts can vary significantly how will the IESO determine the reference parameters for each? Would a formulaic approach determined by hours offline be more accurate rather than limiting to three start states?	The three state design provides flexibility for generators to vary their hot, warm and cold start values to reflect accurate 'warmer' or 'colder' conditions. Providing market participants with the ability to vary their dispatch data gives market participants greater control to manage changes relative to a formulaic, hours offline approach. The methodology to determine the reference quantities for each thermal state is intended to reflect the capabilities that a resource is able to provide to the market. Considerations for what capability is available can be raised during the reference level/quantity engagement process.
237	Offers, Bids, and Data Inputs	Emera Energy	The current pseudo-unit model has some limitations which could potentially be addressed via MRP: - The change in efficiency as derived by the number of GTs online. For example, a 3x1 operation can produce more output than three pseudo 1x1s. Currently there is no way to reflect this in the registration data. If a 3x1 facility registers the PSUs based on a 3x1 maximum, then if only one PSU operates, the plant physically cannot reach the output expected. If the facility registers the PSUs based on a 1x1 maximum the efficient gained by operating in a 2x1 or 3x1 configuration is not accounted for. - The detail design document identifies a "Steam Turbine 10-min Operating Reserve Contribution" which provides an allocation of OR to the ST; however, under certain operations OR may not be available or may not be available outside of certain bounds, how is this reflected to the IESO? - The MLP on the CTs may be different depending on the number of CTs online. There is currently no way to express this in the PSU model.	The PSU model assumes a 1x1 configuration when the PSU is evaluated for commitment. Therefore, it cannot recognize differences in efficiency or MLP due to different operational configurations. To address these two limitations would require an overhaul of the PSU model with a different way of modelling combined cycle facilities. Market participants have flexibility to submit offers and dispatch data that best reflects the physical capabilities for their resources' anticipated configuration. Like today, in situations where PSU are scheduled in a configuration that requires a higher MLP than is reflected in dispatch data, market participants have the ability to request a minimum generation constraint to prevent equipment damage (SEAL). The "Steam Turbine 10-min Operating Reserve Contribution" parameter was proposed to address stakeholder concerns with the PSU model producing 10-min reserve schedules that a steam turbine would be incapable of meeting. Through further design discussions, it became apparent that this parameter was not the right solution to address a number of concerns raised by stakeholders through their design feedback. Additional concerns include 10-minute operating reserve schedules in the duct firing range and the accuracy of minimum loading point schedules for different combustion turbine and steam turbine configurations. Based on these considerations, the "Steam Turbine 10-min Operating Reserve Contribution" parameter will be removed from the design. Compliance aggregation is an alternate solution available to market participants, and a new registration parameter will be included for market participants to declare whether 10-minute reserve can be scheduled in the duct firing range. Compliance aggregation in effect makes an 'infeasible' energy or reserve schedule on an individual resource 'feasible' as it allows the market participant to meet that schedule with the other resources at the facility. The registered option for 10-minute reserve in duct firing mode will be used to inform the calculations engine whether or not 10-minute reserve can be scheduled for the PSU resource. The Facility Registration, Offers Bids and Data Inputs, Grid and Market Operations Integration and Calculation Engine design documents will be updated to reflect this design change.

ID	Design Document	Stakeholder	Feedback	IESO Response
488	Offers, Bids, and Data Inputs	Ivaco Rolling Mills	With Reference to the Facility Registration Detail design section 3.5.2, Ivaco Rolling Mills believes that Price Responsive Loads should be able to register as a contributor to a virtual hourly demand response resource. This provides more flexibility to loads, aggregators and the IESO. The tool limitation should be addressed from the start to allow for this flexibility.	The unique registration requirements provided to virtual HDR in an aggregated portfolio for the purpose of the capacity market create problems for energy market tools to accurately account for a non-dispatchable load seeking to participate as a PRL in the energy market. Failing to properly do so would have adverse impacts to market settlement and demand forecasts. The IESO is considering what modifications are required to the registration of an aggregated portfolio within the capacity auction in order to facilitate participation as a PRL. The detailed design document will be revised to enable a contributor to a virtual HDR portfolio to participate as a PRL, conditional on those modifications made in the capacity market.
128	Offers, Bids, and Data Inputs	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. [...] To improve OR scheduling efficiency and reduce the risk of infeasible schedules, OPG proposes a new parameter term, “Energy + OR Limit”, which specifies the maximum combined quantity of energy plus OR that can be sustained for one hour given water constraints. This new parameter would be particularly beneficial in the day ahead timeframe to reduce the likelihood of an infeasible schedule. An example of how this new parameter would affect joint optimization is shown in Appendix A.” [...] OPG also recommended that the IESO 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. Appendix A (Comment 4) The Issue: The quantity a resource can achieve and sustain in an ORA is contingent on the current energy dispatch which fluctuates based on energy price and the actual output which may differ due to different reasons such as a compliance deadband. There is no parameter to limit the total amount dispatched for energy and scheduled for OR. [...]	The request for an additional parameter for energy plus OR 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.

ID	Design Document	Stakeholder	Feedback	IESO Response
134	Offers, Bids, and Data Inputs	OPG	Comment 9 [...] Whereas we generally support the IESO's high level design views, it does not appear that these concepts have been transferred effectively into the detailed design. Since the publication of the high level design, it appears the IESO revised the design to the following: - Use of Availability Declaration Envelope (ADE) conditions similar to today's DACP to solve the participation concern noted in the above text. (NOTE: OPG will include a detailed comment detailing issues with the decision to retain the ADE in its Grid & Market Operations Integration submission) - Limit the use of hydroelectric parameters to situations where a safety, equipment, or applicable law (SEAL) constraint exists. This restriction prevents these parameters from being used to help create feasible day-ahead and pre-dispatch schedules when water conditions change during the day. Based on these changes, OPG no longer expects day-ahead and real-time schedules to converge and the expectation is that divergence will occur in real-time leaving market participants to manage the uncertainty and buyback risk between the two markets with only offers. The above IESO decisions have decreased the certainty and transparency of day-ahead and real-time schedules, which will require market participants to self manage hydroelectric resources in both day-ahead and real-time schedules through: - hourly offers dependent on passing Market Power Mitigation reference level and quantity assessments, - new hydroelectric dispatch data parameters (changes restricted to SEAL only), and - reliance on real-time must run constraints instead of using good utility practice/proactive approaches for managing physical and operational considerations.	The ADE design has been revised to provide market participants with additional flexibility for ADE changes between day-ahead and real-time. The response to the ADE feedback submitted for the Grid and Market Operations Integration design document was posted October 20, 2020. See ID # 339. The design has been revised to recognize that market participants are limited in their ability to forecast the magnitude of these constraints with absolute certainty in advance of the real-time hour. The submission requirements for the new hydroelectric parameters for reasons required to prevent the resource from operating in a manner that 'reasonably could be expected' instead of 'would be expected' to endanger the safety of any person, damage equipment or violate any applicable law. Revisions to these dispatch data parameters in the pre-dispatch timeframes will be subject to the same revised criteria. With respect to feedback regarding the reliance on real-time must run constraints, responses are provided on the specific feedback received for each hydroelectric dispatch parameter. In general, the design cannot allow for hydroelectric pre-dispatch schedules other than those that reflect a must-run condition to be reflected into the corresponding real-time hour as non-dispatchable quantities because such constraints would preclude other dispatchable resources from being competitively evaluated to respond to changes in system conditions as the real-time hour approaches.

136	Offers, Bids, and Data Inputs	OPG	[…] OPG proposes the MHO parameter should be designed to: • Be used in day-ahead, pre-dispatch, and real-time calculation to reflect physical/operating constraints […] • Provide a feasible day ahead schedule that has evaluated MHO. • In the pre-dispatch calculation engine evaluate the submitted MHO amount in terms of whether a hydroelectric station is scheduled above the MHO. […] • In the real-time calculation engine, if the pre-dispatch calculation engine evaluates and schedules a resource for a MW quantity that is greater than or equal to its MHO, apply a minimum constraint to the MHO or a maximum constraint to 0 MW. […] • Allow hydroelectric operators to make decisions about sluicegate operation on an hourly basis instead of 5 minute basis. […] • Allow energy and operating reserve flexibility and dispatch above the MHO amount. Based on the above principles, the following alternative wording to the MHO parameter is proposed: "Minimum hourly output will be a new optional hourly dispatch data parameter used to represent the minimum amount of energy, in MWh, that a generation unit associated with a dispatchable hydroelectric generation facility either generates, or forgoes the opportunity to generate, depending on the day-ahead and pre-dispatch calculation engine evaluations. A default value of 0 MWh will be used if a minimum hourly output is not submitted. Based on the PD-2 schedule produced by the pre-dispatch calculation engine, if the PD-2 schedule is greater than the MHO submitted then a minimum constraint to the MHO value will be transferred to the real-time calculation engine or a maximum constraint of 0 in the corresponding real-time hour. If a MHO minimum constraint is transferred to the real-time calculation engine, the generation unit will remain fully dispatchable above the minimum hourly output value. Registered market participants will only be eligible to submit minimum hourly output quantities for generation units associated with a dispatchable hydroelectric generation facility. A minimum hourly output value can be submitted if: • spill restrictions are anticipated to prevent the generation unit from responding to dispatch instructions between 0 MW and the minimum hourly output value; or • following a dispatch instruction between 0 MW and the minimum hourly output value the registered facility is unable to follow the dispatch instruction as its operation may endanger the safety of any person, damage equipment, or violate any applicable law. The following criteria should also apply: • Minimum hourly output quantities submitted as dispatch data shall not exceed the maximum quantity of the energy offer for the generation unit; and • Sum of all hourly must-run quantities submitted as dispatch data must be less than or equal to the maximum daily energy limit submitted as dispatch data for the generation unit."	The proposed alternative wording suggests two changes be made to the minimum hourly output (MHO) parameter design. One request is to allow MHO-based pre-dispatch schedules of 0 MW to be used as maximum constraint in the corresponding real-time hour and MHO-based pre-dispatch schedules of greater than or equal to MHO to be used as minimum constraints in the corresponding real-time hour. This design change will not be made because the timing of spill restrictions varies for different hydroelectric resources and for different market participants. In today's market, spill restrictions are at times not imposed until much closer to or even during the dispatch hour. The future design must preserve the ability for dispatchable resources to maintain their dispatchable range until the market participant no longer expects that range to be dispatchable. If constraints were prematurely applied, it would preclude that resource and other market participant resources from being competitively evaluated to respond to changes in system conditions as the real-time hour approaches. The other requested change is to relax the requirement for the MHO parameter to be submitted for spill restrictions that 'may' instead of 'would' be expected to prevent the resource from endangering the safety of any person, damaging equipment, or violating any applicable law. The submission requirement will be revised from 'would to be expected' to 'reasonably could be expected' to recognize that market participants are limited in their ability to forecast the spill restriction with absolutely certainty in advance of the real-time hour.

ID	Design Document	Stakeholder	Feedback	IESO Response
138	Offers, Bids, and Data Inputs	OPG	Comment 13 - The parameters MIN DEL and MAX DEL are MWh amounts. Water management plans do not deal with MWh - they deal with volumes of water over a day. o A translation from volumetric to energy requires an assumption of an operating point, which is usually assumed to be a unit's efficiency point for future based calculations. o During day ahead, assuming the same physical characteristics as in the Forbidden Regions example from Comment #12, scheduling a unit to 50 MW which is below its efficiency point of 55 MW will use more water than expected during MIN/MAX DEL submissions. o During pre-dispatch and real-time, the DEL is evaluated hourly based on actual discharges (not MWh), inflows, operating limits, a correction for IESO inferred actual DEL usage based on MWh (not flow), and a forward looking calculation of remaining MIN and MAX DEL amounts. o Due to the above, DEL calculations require provisions to be updated on an hourly basis and are most accurate when units operate at their best efficiency points. Incorporating the above fundamental principles, the following alternate wording for Minimum Daily Energy Limit (Min DEL) is proposed: “Min DEL will be a new voluntary dispatch data parameter that represents the minimum amount of energy, in MWh, that a generation unit must be scheduled to supply within a dispatch day to prevent the registered facility from operating in a manner that could endanger the safety of any person, damage equipment, or violate any applicable law. This parameter will be used by day-ahead, pre-dispatch, and real-time calculation engines. (See Grid & Market Operations Integration for details on application to RT calculation engine.) This parameter will only be available to registered market participants submitting dispatch data for generation units registered with a dispatchable hydroelectric generation facility. A Min DEL value can only be submitted for anticipated daily must-run conditions required to prevent the registered facility from operating in a manner that may endanger the safety of any person, damage equipment, or violate any applicable law.”	The design allows for market participants to update their Min and Max daily energy limit (DEL) values throughout the day so that the pre-dispatch calculation engine can evaluate the most recent data for the resource. This decision is reflected in the Grid and Market Operations Integration design document. The DAM and pre-dispatch submission requirements for min DEL will be revised so that it may be submitted for daily must run conditions that ‘reasonably could be expected’ to prevent a resource from endangering the safety of any person, damaging equipment or violating any applicable law. The change from 'would be expected' to 'reasonably could be expected' recognizes that market participants are limited in their ability to forecast the magnitude of a hydroelectric must run condition with absolutely certainty in advance of the real-time hour. The IESO is unable to revise the submission requirements for this constraint from ‘would be expected’ to ‘could be expected’ because a min DEL submission will preclude other resources from being competitively scheduled if the min DEL constraint becomes binding. In comparing OPG's proposed description for the min DEL parameter to the current description in the design document, the IESO will update the Min DEL description to clarify that Min DEL is a voluntary parameter; and that Min DEL will be used by the RT calculation engine under the pre-dispatch conditions described in Section 3.7.2.2 of the Grid and Market Operations Integration detailed design document.

ID	Design Document	Stakeholder	Feedback	IESO Response
140	Offers, Bids, and Data Inputs	OPG	Comment 15 [...] OPG appreciates that in the future both the day-ahead and pre-dispatch calculation engines will use the Maximum Number of Starts per Day (MNSPD) parameter. However, without addressing the wear and tear caused by unit starts and stops in real-time by respecting the MNSPD parameter, there will be an increased risk of equipment damage and resultant outages if the pre-defined thresholds are exceeded. In order to mitigate this situation, the market participant will need to submit an outage in real-time once MNSPD is reached which will require the IESO to manage a larger number of outages. Example: It is common for some resources to be started at xx:45 and stopped at xx:00 or started xx:05 to xx:15 on an hourly basis to react to changes to interties and primary demand. Without some consideration of a link between pre-dispatch and real-time calculation engines, resources could use up the MNSPD early in the day and face the possibility of being forced out for the remainder of the day. On a cascade river system, the upstream/downstream stations may also be forced out. OPG is concerned this will remove available capacity from later hours (that could be avoided through an improved design) and subsequently create buy back risk between day ahead and real time schedules. OPG proposes the real-time calculation engine considers the use of starts in the current real-time hour vs. saving them for subsequent pre-dispatch hours. Also, in the event the MNSPD is exceeded for the day and the market participant keeps the unit available, a process should be created that allows market participants to NULL or remove the MNSPD. If this process is not created, pre-dispatch schedules for the remainder of the day will be zero yet the unit remains available for dispatch in real-time. This creates an inefficient market outcome.	The real-time calculation engine's intra-hour optimization with a look ahead period of eleven, five minute intervals is not capable re-evaluating the intra-day use of starts in future hours of the pre-dispatch look-ahead period. Market participants can manage the opportunity cost of balancing real-time deviations from DAM schedules by adjusting their offer prices in the hours that starts are scheduled. Submitting higher opportunity costs to reflect the additional use of starts, in effect, provides a way for the real-time calculation engine to consider whether additional starts should be used now or saved for subsequent hours. A larger volume of outage slips would not be required to manage MNSPD relative to today's market. Real-time dispatches should have greater alignment with pre-dispatch schedules that respect MNSPD, relative to today's pre-dispatch schedules that do not respect MNSPD. The design allows for market participants to null or remove the MNSPD for future pre-dispatch runs in the event that MNSPD is exceeded and the market participant elects to keep the unit available.

142	Offers, Bids, and Data Inputs	OPG	[…] OPG proposes the section on Linked Resources, Time Lag, and MWh Ratio on page 27 be rewritten to: "Linked resources, time lag and MWh ratio will be three new daily dispatch data parameters used to represent the energy production and time lag relationship between generation resources on a hydroelectric cascade river system. The energy produced by upstream resources require a proportional amount of energy to be produced by downstream resources after a period of time to represent the physical/operational constraints of a cascade river system. Registered market participants will have the ability to link eligible resources and stations such that all of the hourly energy offers for the upstream resources will be evaluated with all of the hourly energy offers for linked downstream resources. Time lag represents the amount of time it takes for the water discharged from the upstream resource to reach a linked downstream resource. Registered market participants would submit a time lag value of zero to indicate that the energy offers for the linked resources must be scheduled in the same dispatch hour. A time lag value of greater than zero would indicate the linked resources must be scheduled with a delay between them. MWh ratio represents a proportional amount of energy that must be scheduled at a linked downstream resource for every MWh of energy scheduled at the upstream resource. Linked resource, time lag and MWh ratio values can only be submitted to reflect the physical/operational constraints of cascade river systems. The IESO may review the submission of these parameter values to confirm the registered market participant is in compliance with this requirement. The DAM and PD calculation engines will evaluate the energy offers for linked resources, and if optimal to do so, schedule linked resources in respect of the time lag and MWh ratios submitted as dispatch data." In addition to the rewritten section, OPG proposes logic that will transfer pre-dispatch schedules to real-time calculation engine in the form of minimum constraints to maintain balance on a cascading river system. When considering which pre-dispatch schedule was appropriate, OPG considered that the most flexibility is provided to the market by making the latest decision possible while weighing the need to break a link in PD-1 due to local inflow changes, outages, or other SEAL events. It is proposed that the IESO implement logic, transferring a minimum constraint equivalent to the PD-2 schedule to the real-time calculation engine for the upstream station of the cascade, with corresponding minimum constraints implemented based on the PD-2 schedule of the upstream station to the linked downstream stations. The downstream equivalents should receive minimum constraint schedules in real-time unless the links are broken/removed by the participant.	The rewritten proposal suggests relaxing the criteria for which linked resource parameters can be submitted in two ways. One is to change "for intertemporal dependencies" to "for physical/operational constraints". This change cannot be made because the linked resource parameters are only designed to capture the intertemporal dependencies of energy production and time lag between cascade resources, not any physical/operational constraint for those resources. Other parameters such as Min DEL, Hourly Must Run and Minimum Hourly Output have already been included in the design for market participants to reflect those physical/operational constraints, which may also be used for cascade resources. The other requested change is to remove the requirement for linked resources parameters to only be submitted for intertemporal dependencies that 'would be expected' to prevent the resource from operating in a manner that endangers the safety of any person, damage equipment or violate any applicable law. The IESO will revise the requirement from 'would be expected' to 'reasonably could be expected' to recognize that market participants are limited in their ability to forecast the magnitude of energy production and time lag relationships with absolutely certainty in advance of the real-time hour. Pre-dispatch schedules for linked resources will not be used as minimum constraints for these resources in the real-time dispatch since the dependency for a downstream resource to generate does not occur until the upstream resource generates. Unless a must run requirement is present on either the upstream or downstream resource, linked resources must remain flexible to be scheduled within their dispatchable range up to and including the real-time dispatch hour. Without a must run condition present, applying minimum constraints for these resources will preclude other dispatchable resources from being competitively evaluated to respond to changes in system conditions as the real-time hour approaches.

ID	Design Document	Stakeholder	Feedback	IESO Response
145	Offers, Bids, and Data Inputs	OPG	Comment 20 - The design indicates that current hydroelectric daily dispatch data can only be revised hourly for the rest of the day due to a SEAL reason. It is recommended that changes to hydroelectric daily dispatch data (from Table 3-1) be allowed with every hourly submission during the day to allow market participants to better reflect changing/evolving physical conditions including: • Linked resources, time lag and MWh ratio • Forbidden regions • Max/Min DEL • Max number of starts per day As hydroelectric conditions change, and unplanned outages and transmission constraints arise, market participants require the flexibility to modify the daily dispatch data parameters hourly to reflect physical operational restrictions.	The design allows for hourly revisions to daily dispatch data to reflect changes in physical operating constraints. The allowable criteria for revisions will be changed from 'would be expected' to 'reasonably could be expected' to prevent the resource from operating in a manner that endangers the safety of any person, damages equipment or violates any applicable law.
151	Offers, Bids, and Data Inputs	OPG	[…] Using predefined MGBDT values to determine if Hot/Warm/Cold dispatch data applies for pre-dispatch calculation will not always accurately reflect the condition of a plant. […] OPG suggests that the Market Participant be allowed to specify in the hourly dispatch data what the thermal state of the unit is for any given hour rather than using the MGBDT parameter to determine its state. […]	Hourly identification of thermal status is not required since the minimum generation block down time (MGBDT) and other thermal state values can be updated by the participant to reflect prevailing conditions. Updates to these values allow subsequent runs of the pre-dispatch engine to infer the correct thermal state for future hours. For instance, increasing the value of MGBDT would inform the engine that a second start would take longer, and reducing the value of MGBDT would mean a second start could be scheduled sooner.
154	Offers, Bids, and Data Inputs	OPG	Comment 29 - If the pre-dispatch calculation engine is modified to only use dispatch data for imports and exports with DAM schedules, reliability may be impacted if the IESO does not schedule enough resources to meet the increased demand if exports outside of the DAM window are not evaluated. Market efficiency may also be impacted if a NQS resource is committed in lieu of a more economic import that would have been scheduled in pre-dispatch. Also, OPG is uncertain if intertie transactions will be sufficiently incented to participate in the DAM. Has the IESO considered additional incentive mechanisms for DAM participation similar to what's used in some U.S. jurisdictions?	The IESO does not anticipate any significant or pervasive reliability impacts resulting from the evaluation of non-DAM scheduled exports in PD forecast hours T+1 and T+2 only. Any increased demand from these exports will be the product of an optimized pre-dispatch engine schedule. In the event of an unforeseen adequacy concern, the IESO will employ control actions described in Market Manual 7.1, Appendix B.2 "Emergency Operating State Actions (IESO and External Control Area Deficiency)". During high level design, the IESO considered incentive mechanisms and determined that intertie traders have sufficient incentives to participate in the DAM with the ability to receive financially binding day-ahead schedules.

ID	Design Document	Stakeholder	Feedback	IESO Response
156	Offers, Bids, and Data Inputs	OPG	OPG requests clarification on whether Operating Reserve Ramp Rate is part of hourly offer submission or dispatch data submission. [...] It is recommended that the Operating Reserve Ramp Rate be an hourly submission that can vary for different hours of the day. [...] [...] It is recommended that a new parameter be introduced that will be able to identify what set of ramp rates to use and for which hours depending on the thermal state of the unit.	Operating reserve ramp rate will be an hourly dispatch data submission that is provided for every hour an offer for operating reserve is submitted. The operating reserve ramp rate can be different for each hour it is submitted. A new parameter to associate ramp rates with thermal status is not required because thermal status reflects the operating conditions of a resource in an offline state. Ramp rates are only considered for a resource in a online state at values above its minimum loading point.
157	Offers, Bids, and Data Inputs	OPG	Comment 32 - IESO proposes submission and cancellation timelines for SMO requests be revised in the future market. From the Grid and Market Operations Integration detailed design document it states: "In the future market, for SMO that requires an outage to a critical transmission element: - Requests to segregate must be submitted by 08:00 EPT for the following dispatch day. This will provide the IESO with sufficient time to assess the SMO request for reliability and publish associated transmission limit changes;" OPG proposes that SMO transactions should not be limited in real time regardless of an outage to a critical transmission element. We would like some rationale as to why an outage to a critical transmission element should prevent a market participant from using SMO in real time. In addition OPG requests SMO in day ahead be revised to be made by 10:00 EPT, respecting the proposed DAM market timelines. Please provide a definition of what constitutes a "critical transmission element", and provide a list of included elements. A market participant standardized report indicating the "critical transmission elements" on outage should be issued to participants notifying them of their limitations to request SMO.	Segregated Mode of Operation (SMO) involves taking a generation facility out of the available supply and, in some cases, changing transmission limits. Today, the SMO process allows generation units to segregate using short notice outage requests, up to 2 hours before a dispatch hour. A short notice SMO request that introduces a change in transmission limits from day-ahead to real-time does not impact the current market. In the future, a financially binding DAM means there will be an impact if SMO requests that impact transmission limits are allowed after the DAM results are published. Restrictions are necessary so that a market participant is not able to initiate a change to a transmission limit after the DAM completes that would give them market power. This change is required to allow all market participants equal access to transmission limit data. The deadline for SMO requests into the day-ahead market cannot be extended to the DAM submission deadline of 10:00 EPT because the IESO would have no time to assess the request and provide all market participants with sufficient notice for changes to transmission limit data. As defined in Market Manual 7.3: Outage Management, a critical transmission element is defined as having a material impact on the reliability and/or operability of the IESO-controlled grid or the interconnection when removed from service. A list of critical elements cannot be not published to the market for confidentiality reasons. However, transmission limit data is regularly published to market participants via the Transmission Facility Outage Limits reports to reflect the impact of critical transmission element outages.

ID	Design Document	Stakeholder	Feedback	IESO Response
159	Offers, Bids, and Data Inputs	OPG	Comment 34 - When a reliability commitment is given to an NQS in advance of first pre-dispatch run, will the IESO notify all market participants that such a commitment has been given, and for which specific hours of the day? OPG recommends this information be provided as part of a public report rather than a system advisory notice. This allows for archiving this report with similar data on a trade date. This is beneficial for after-the-fact analysis and may aid in ex-post discussions on Market Power Mitigation with the IESO.	An advisory notice will be published to notify all market participants for reliability commitments issued for the next dispatch day after DAM and before the 20:00 EST pre-dispatch calculation engine run. The advisory notices will be similar to those issued for out-of-market control actions made in advance of or during extreme conditions, as described in Market Manual 7.1, section 2.4. An archived public report is not necessary to support after-the-fact analysis in lieu of an advisory notice since advisory notices are archived.
160	Offers, Bids, and Data Inputs	OPG	Comment 35 - Please provide information on why the IESO proposes to set the hourly forecast value to 0 MW when this is not the expected condition. OPG recommends the Lake Erie Circulation (LEC) Forecast be published in a standardized report prior to the Day Ahead Submission window opens (i.e. prior to 06:00 EPT) and also hourly during the Pre-dispatch timeframe, this report should also indicate any planned or forced outages to the Phase Angle Regulators (PARs), which would lead to the inability to regulate the flow for LEC.	The hourly Lake Erie Circulation (LEC) forecast is typically set to 0 MW with the expectation that phase angle regulators are available to adjust actual LEC in real-time to 0 MW. If phase angle regulators are not expected to be able to regulate LEC to 0 MW in any given hour, the LEC forecast would be adjusted to reflect anticipated LEC for that hour. The design does not constitute a need for LEC forecasts to be published in the future market. Market participants are able to participate in the future market as they do without an LEC forecast in today's market. The transmission outages reports listed in Table 3-17 of the Publishing and Reporting Market Information detailed design chapter provide planned and forced outage information that includes phase angle regulators and their associated equipment.
161	Offers, Bids, and Data Inputs	OPG	Comment 36 - OPG had provided the following comments in our SSM HLD Stakeholder Feedback regarding negative pricing: “OPG believes there is technically based merit for negatively priced offers and welcomes further discussion on this topic. Should changing the value of the negative MMCP be considered, it will be important to have a means for distinguishing dispatch order if there is insufficient price separation between supplier offers; in particular, energy limited renewable facilities.” The IESO’s response to the feedback was the following: “Thank you for your feedback. The issue of negative pricing will be addressed with stakeholder input in detailed design.” OPG did not see the issues around market participant’s requirements to submit negative priced offers to provide sufficient price separation between offers for energy limited renewable facilities and its impact of potentially setting negative locational prices addressed in this detailed design document, and would appreciate some clarity around how the IESO intends on addressing this topic. We would again welcome further stakeholder discussions on the subject of negative MMCP.	The offer floors currently in place for nuclear and variable generation resources in today's market will continue to be used to distinguish dispatch order in the future market. For all other resources including energy limited renewable hydroelectric resources, offer price submissions down to and including negative MMCP of -$2000 are permitted.

ID	Design Document	Stakeholder	Feedback	IESO Response
162	Offers, Bids, and Data Inputs	OPG	For market transparency, the IESO should publish a report to inform market participants of changes to Penalty Prices with a frequency that allows Market Participants to adjust offers accordingly.	The prices used in the constraint violation penalty curves are not expected to change frequently and therefore do not need to be published in a report. The IESO will provide the same level of transparency by publishing penalty prices in the market manuals.
165	Offers, Bids, and Data Inputs	OPG	Comment 40 - Summing the demand forecast for the four zones to produce the province-wide demand forecast will magnify error and increase likelihood for more price volatility across zones, given that the four zonal forecasts will have already been rounded up to ensure self-sufficiency. Given Ontario's large geographic area, forecasting on a global level can offset errors inherent to zonal forecasting caused by rapidly changing weather patterns across smaller planning areas. OPG suggests the IESO offset this rounding impact when aggregating the four zonal forecasts into a single province wide forecast. Or develop the forecasts using a bottom-up approach (i.e. zonal forecasts that capture the unique load types by zone that are then aggregated up) rather than the top down approach that assigns shares. OPG suggests the IESO publish zonal forecasts that are distributed by nine zones, which are consistent with the nine virtual zones. This will allow Market Participants in each of these nine zones to plan their resources better based on expected zonal demand and zonal constraints.	Summing of the four area demand forecasts is figuratively used in the design document for publishing purposes. In practice, the DAM, PD and RT calculation engines will use four separate forecasts which means rounding impacts will not be present during optimization. The IESO will update the Demand Forecast section of the design document to clarify the forecasts are accounted for separately in the engines. The IESO will not produce nor publish forecasts for additional subzones within the southeast and southwest demand areas because the number of demand forecasts is not exclusively tied to congestion patterns. The four areas were primarily designed to produce a more accurate load distribution by accounting for weather patterns that are common to geographic zones, not virtual zones. Virtual zones are financial constructs in the DAM that have no bearing on how a market participant plans its physical resource operation.
217	Offers, Bids, and Data Inputs	OWA	There are insufficient details are included in the design to determine if new hydro parameters will be effective. These parameters need to evolve as other elements of the design are finalized. For example, the market power mitigation design will have a significant impact on requirements for effective hydro modelling. One key item is that some of the new hydro parameters are not applied in real-time (e.g. linked hydro resources), which means that market participants (MPs) will still need to manage operating restrictions through their offer strategy. This could cause divergence between day ahead and real-time LMPs since offers depend on how/when the parameters apply. At the July 8 meeting, the IESO clarified that the six new parameters introduced for dispatchable waterpower are voluntary and that owners can continue to choose to manage facilities through bids and offers. The OWA would appreciate the opportunity to continue to discuss these parameters bilaterally with the IESO.	The entire design has been published for stakeholder review since the time this feedback was received. Additional feedback is being reviewed and responded to. The market power mitigation design does not impact how physical operating constraints are designed as dispatch data. Rather, it is the mitigation design that determines reference levels required for that dispatch data. Additional considerations about the market power mitigation design should be solicited through the technology-specific reference level/quantity stakeholder engagement sessions. The inability for the real-time calculation engines to evaluate some of the new hydro parameters does not require a market participant to manage infeasible dispatches with their offers. If an infeasible dispatch is produced in real-time, manual constraints can be applied by the IESO to produce feasible dispatches. The same real-time price would be produced whether that feasible dispatch is driven by the market participant's offer or the IESO's manual constraint. Differences between day-ahead schedules and real-time dispatches signal a change in system conditions. When system conditions change, real-time prices should deviate from day-ahead prices to achieve efficient market outcomes.

ID	Design Document	Stakeholder	Feedback	IESO Response
218	Offers, Bids, and Data Inputs	OWA	The Offers, Bids and Data Inputs document states that hydro parameters including Hourly Must Run, Min Daily Energy Limit, Minimum Hourly Output and Linked Resources are only permitted to be used "to prevent the registered facility from operating in a manner that would endanger the safety of any person, damage equipment, or violate any applicable law." These parameters are needed to prevent hydroelectric stations from being assigned infeasible schedules by the day-ahead (DA) and pre-dispatch (PD) calculation engines and not for SEAL reasons. SEAL, as currently defined, is extremely difficult to justify in DA and early PD as scheduling has some degree of flexibility until water is in motion and upstream/downstream operating restrictions are forecast. In addition, daily hydro parameters can be only be changed hourly for remainder of day for SEAL reasons. The design should allow them to be modified with every hourly submission so that the most current info is used for subsequent PD runs. Intra-day modifications to linked resources are needed as evolving flow and unit conditions change time lags between cascading stations. At the July 8 session, IESO staff confirmed that it was willing to consider modifications to the standard definition of SEAL to address the unique characteristics of hydro operations. The OWA will develop an alternative definition for the IESO's consideration.	The design documents will be updated to allow these parameters to be submitted in the DAM and pre-dispatch timeframes to reflect physical operating constraints for reasons that 'reasonably could be expected' instead of 'would be expected' to prevent the resource from operating in a manner that endangers the safety of any person, damages equipment or violates any applicable law. This change recognizes that market participants are limited in their ability to forecast the magnitude of these constraints with absolute certainty in advance of the real-time hour. Revisions to these dispatch data parameters in the pre-dispatch timeframes will be subject to the same revised criteria.
219	Offers, Bids, and Data Inputs	OWA	The first run of PD engine at 20:00 is too late in the day to update hydro offers to reflect evolving water conditions. Under normal conditions, water management activities would already be in progress to meet the DA schedules received earlier in the day, reversing or delaying these may not be readily feasible. Under extreme weather conditions, such as a rainfall event greater than forecast, impairment to unit capacities beyond the Generator's control require some methodology to accurately inform the IESO as to the revised capacities without penalty to the Generator. The IESO has advised that this decision was made in high level design and that a key limitation to changing this is the computing time required of the DSO. Nonetheless, the OWA recommends that the IESO revisit this design decision within the context of its implications for hydro operations.	The first start of the pre-dispatch engine is unable to be advanced from 20:00 with pseudo-unit dispatch data and the additional hydroelectric dispatch data being evaluated over a long multi-hour look ahead period. The timing of the pre-dispatch engine has no bearing on a market participant's ability to update their day-ahead offers to reflect the opportunity cost of deviating from their day-ahead market schedules.
220	Offers, Bids, and Data Inputs	OWA	The model appears to assume that all hydro spill is dispatchable and can change every five (5) minutes. For example, Minimum Hourly Output (MHO) seems to imply that Generators spill as a normal course of action. Sluice gates are not dispatchable and must not be considered nor contemplated as a tool to facilitate dispatch instructions.	The minimum hourly output quantity is voluntary parameter. If submitted, it will only be used to evaluate hourly schedules in the DAM and pre-dispatch timeframes, not five minute dispatches in the real-time market. To reflect non-dispatchable quantities in the real-time market, a market participant should submit an hourly must run parameter value for that hour.

ID	Design Document	Stakeholder	Feedback	IESO Response
222	Offers, Bids, and Data Inputs	OWA	Maximum starts/day parameter need to also factor in maximum starts/hour and minimum runtime after each start. Bearing restrictions (cool out after shutdown) must be factored in, without having to resort to submission of outage slips.	Maximum starts per hour are computationally infeasible in the DAM and pre-dispatch timeframes because resources are scheduled in hourly increments. A single start must scheduled for an entire hour. The DAM and pre-dispatch calculation engines inherently respect a minimum run time and a minimum cool out period of one hour. In a multi-hour optimization, a start must be scheduled for at least an hour and subsequent starts cannot be scheduled without a minimum one-hour delay from the previous start. The real-time calculation engine is not capable of evaluating any additional parameters due to run-time constraints. Real-time control actions used to manage intra-hour start and cool out restrictions in today's market will continue to be available in the future.
223	Offers, Bids, and Data Inputs	OWA	Dispatch at less than best efficiency gate opening for fixed blade hydro turbines is, from a "fuel" perspective more expensive and in the longer run more expensive for the market. Compensation for running at inefficient gate opening should be considered.	As with today's market, market participants can continue to reflect costs associated with different quantities in the future market through their hourly offers.
224	Offers, Bids, and Data Inputs	OWA	The proposed # starts methodology is flawed. Using 0MW or breaker open as an indicator that unit is stopped is not accurate nor reflective of the true state of the machine, rather actual "stop" indication from controls is required.	The request to use actual stop indication suggests that the maximum number of starts parameter is interpreted as being evaluated by the real-time calculation engine during the dispatch hour. This is not the case. Maximum number of starts per day is a daily dispatch data parameter designed for multi-hour optimization in the day-ahead and pre-dispatch timeframes. The materials for the hydroelectric dispatch data engagement session held on November 14, 2019 provide illustrative examples of how this parameter is evaluated. The materials can be found on the Energy Detailed Design Engagement page.
225	Offers, Bids, and Data Inputs	OWA	Minimum daily energy limit (Min DEL) includes wording to the effect pre-dispatch schedules are dependent on storage or spill of both upstream and downstream resources. Wording further suggests that RMP must submit must run offers to account for upstream dispatch. How is RMP expected to know what the upstream MP is doing if they are not operated by the same entity?	The Min DEL and hourly must run parameters are new to the market design, however the physical operating constraints they represent are actual constraints that market participants with different resource ownership on the same cascade river have been managing in today's market. Market Participants can rely on the existing mechanisms they have to manage this uncertainty in the future market. If this uncertainty precludes a resources from following dispatch instructions in the real-time market, the market participant may contact the IESO to take manual actions to produce a feasible dispatch as they may today.

ID	Design Document	Stakeholder	Feedback	IESO Response
226	Offers, Bids, and Data Inputs	OWA	For cascaded river systems: a) the concept of MW ratio is technically flawed. Such a ratio is valid only at one point on the operating curves and is dependent on the turbine & generator efficiency characteristics and the operating head at each site and which are non-linear relationships. b) Time lag between facilities is flow dependent – at lower flows, the lag is longer and conversely under high flow conditions the lag is shorter. It is not a constant. c) Cascaded resources are not necessarily all owned/operated by dispatchable Market participants. Some facilities are presently dispatched as an aggregated resource. Is the IESO considering breaking up aggregated resources? This will result in inefficient dispatch and water utilization.	The calculation engines are not capable of evaluating the MWh ratio as a non-linear relationship. The linear-based MWh ratio parameter that is included in the design can be revised throughout the pre-dispatch timeframe to reflect changes in physical operating constraints. Time lags can also be revised to be longer or shorter. Market participants are not required to use these parameters in the future market. They may continue to only use the dispatch data they use in today's market. No, the design is not breaking up resource aggregates. The design reflects the aggregation available in today's market.
489	Offers, Bids, and Data Inputs	Power Advisory	The Consortium offers the following recommendations. • IESO should establish a distinct stakeholder engagement to work through MRP design details relating to hydroelectric generators. o This stakeholder engagement is required, due to complexity of new registration and dispatch data requirements for dispatchable hydroelectric generators, more details and need to further clarify technical aspects regarding these new requirements, and how these new requirements will work as inputs towards optimizing schedules and commitments for energy and operating reserve (OR) supply, including formulation of market-clearing Locational Marginal Prices (LMPs) for energy and OR. • IESO should commit to shortage/scarcity pricing in MRP design and rules to accurately value energy and OR. o The calculation engine detailed design documents are needed to truly assess how pricing inputs will be used in accordance with constraint violation penalty curves and other inputs. The events, actions, and market outcomes from IESO's July 10, 2020 Energy Emergency Alert Level 1, signaling potential for declaration of an Emergency Operating State, is a very good example how wholesale market-clearing prices did not reflect actual power system conditions and needs – sending inefficient signals to the market.	The IESO has been working closely and collaboratively with the sector to move ahead with renewing Ontario's electricity market. For the waterpower sector specifically, that have been multiple opportunities for specific engagements, and there are plans for continued engagement as we move ahead with the Implementation. Further, the IESO is open to discussions with any set of stakeholders, when needed, to clarify aspects of the renewed market. The constraint violation penalty curves described in Table 3-7 of the Offers, Bids and Data Inputs design document will be used to establish shortage prices in the future market that are at or below the current maximum market clearing price of +2000. The DAM, Pre-Dispatch and Real-Time Calculation Engine detailed design documents define when the curves are applied in the engines and how LMPs are set (Sections 3.6.2 and subsection 3.6.2.2 for each document). The actual values that will be used for the future market will be determined during the implementation phase of the MRP.

ID	Design Document	Stakeholder	Feedback	IESO Response
492	Offers, Bids, and Data Inputs	Power Advisory	Section 3.3 – DAM and Real-Time Market Participation […] for variable (i.e., wind and solar) generators (VGs), retention of the ADE framework may pose future risks post expiry of contracts. Under the present ADE framework, IESO uses their centralized energy production forecast for VGs by incorporating respective forecast quantities in the Day-Ahead Commitment Process (DACP). Because DACP does not set market-clearing prices and therefore does not financially commit VGs, VGs do not presently have financial risks based on the DACP. Further, VGs that are registered as dispatchable generators in the IAM have contract provisions to address energy production risks (e.g., curtailment within the IAM). Based on MRP design, the Day-Ahead Market (DAM) will be financially-binding to RTM settlements. This DAM design feature combined with the ADE framework and future expiry of contracts together could result in VGs, and hydroelectric generators, facing financial and energy production risks within IAM several years from now – mainly driven by variable fuel and energy limited fuel (in the case for some hydroelectric generators) from the day-ahead timeframe to real-time dispatch. More specifically regarding dispatchable hydroelectric generators, IESO should permit energy production in RTM to deviate from respective ADE quantities, under real-time conditions where production quantities need to be efficiently aligned with available water. This will better enable efficient energy production based on the capabilities of hydroelectric generators, so long as they are economic in RTM. Based on the operating experience of many Consortium members in all U.S. Independent System Operator (ISO)/Regional Transmission Organization (RTO) wholesale electricity markets, it is the Consortium's understanding that participation from VGs and hydroelectric generators in the U.S. DAMs is mostly voluntary (e.g., this is the case in NYISO, PJM, MISO, SPP, and ERCOT). However, for ISOs/RTOs that administer Capacity Markets, VGs and hydroelectric generators 'must-offer' into the respective DAMs if they have capacity obligations from respective Capacity Markets (as the case may be in NYISO, ISO-NE, PJM, and MISO, as these ISOs/RTOs administer Capacity Markets). However, many renewable generators, particularly VGs, typically do not participate within Capacity Markets, and therefore VGs typically do not have capacity obligation-driven 'must-offers' in respective DAMs. Overall, IESO plans to retain the ADE framework is a unique market design component, relative to U.S. wholesale electricity market designs8, that features 'must-offer'-like qualities through the requirement of establishing facility-specific ADEs for RTM participation. For VGs and hydroelectric generators, this framework could lead to a loss in operational flexibility.	As with today's market, ADE for all dispatchable resources, including VG resources, will continue to be based on its maximum offer quantity. Unlike other dispatchable resources, the maximum quantity that a VG resource can be scheduled for in the DAM is limited to the forecast quantity the market participant chooses to submit into the DAM, not the maximum offer quantity. The forecast quantity may be less than the maximum offer quantity used to establish ADE. For all resources including VG, the ADE framework will be modified to provide market participants with greater flexibility to account for unanticipated changes in prevailing real-time conditions such as ambient temperatures. RT increases to the ADE established in the DAM will be expanded to the lesser of 15% or 10MW, up from today's 2% or 10 MW.

493	Offers, Bids, and Data Inputs	Power Advisory	Section 3.4.2 – Generation Facility Dispatch Data to Supply Energy [...] more details and examples are required to better understand how new dispatch data components may or may not improve the efficient operations of dispatchable hydroelectric generators in accordance with the needs of Ontario's power system. For example, it is not yet clear how new dispatch data may or may not be effective because more details and information are needed regarding the calculation engines[…] • Minimum Hourly Output and Hourly Must-Run o In addition to preventing applicable hydroelectric generators "from operating in a manner that would endanger the safety of any person, damage equipment, or violate any applicable law", it should also help prevent these generators from receiving schedules and dispatch instructions from IESO that may not be operationally feasible. o More details are needed to better understand any compliance issues that may result when hydroelectric generators utilize Minimum Hourly Output and/or Hourly Must-Run dispatch data in anticipation of spill conditions. […] o […] Can Hourly Must-Run quantities to be submitted as dispatch data deviate from Hourly Must-run Quantities from the registration process? • Linked Resources, Time Lag and MW Ratio o This new dispatch data should fall into the Hourly Dispatch Data category […] o The concepts of Linked Resources, Time Lag and MW Ratio requires more stakeholder engagement and work. […] For example, […] if more than one competing MPs own and operate hydroelectric generators on the same cascaded river system, the downstream generator potentially will face operational challenges resulting from variable water availability based on how upstream generators operate. […] o […] more flexibility should be explored regarding how hydroelectric generators may change the Linked Resources, Time Lag and MW Ratio dispatch data as required to enhance efficiencies of operations. • Forbidden Regions […] o The draft detailed design document clearly states that Forbidden Regions submitted as part of dispatch data can deviate from Forbidden Regions that were submitted in IESO's facility registration process. The Consortium supports this, and recommends that same flexibility be applied to the other new dispatch data. […]the Consortium believes IESO will need to review the offer price floors for VGs, in order to improve management of the power system, maximize efficiencies of scheduling and dispatch decisions under localized SBG conditions, and therefore minimize curtailment and other costs to electricity customers. […] On p. 22, in referring to the maneuverable portion of VG energy supply, IESO states "… the remaining available capacity must be priced no less than -$3/MWh", solar generation needs to be added regarding this description, as only wind generation has been referenced.	The DAM, pre-dispatch and real-time calculation engine detailed design documents have been published for stakeholder review since the time this feedback was received. Additional feedback on those designs is being reviewed and responded to. The majority of the new hydroelectric dispatch data parameters are daily parameters that are used by the DAM and pre-dispatch engines to perform intra-day optimization with a look-ahead period of up to 28 hours. The real-time calculation engine's intra-hour optimization with a look ahead period of eleven, five minute intervals is not capable of evaluating multi-hour parameters. Submitting minimum hourly output and hourly must run values for operating conditions that respect person safety, equipment and any applicable law will produce feasible DAM and pre-dispatch schedules, that if dispatched to that schedule value in real-time are operationally feasible. With respect to compliance details, potential non-compliance issues with market rules and market manuals will be assessed on a case by case basis in the future market as they are in today's market. Market participants should have evidence to support compliance with the market rules and manuals. The registration design of Hourly Must Run will be revised. Instead of registering hourly must-run quantities, market participants will only register the ability to submit the hourly must-run parameter as dispatch data. Hourly must run quantities submitted as dispatch data can be adjusted throughout the pre-dispatch timeframe to reflect changes in anticipated must run conditions. As daily data, the design allow for linked resource parameters, including MWh ratio, to be adjusted as required throughout the pre-dispatch timeframe to reflect anticipated changes in physical operating restrictions. The calculation engines are not capable of evaluating the complexity of linked resource, time lag and MWh ratios parameters as hourly dispatch data. The physical dependencies that the linked resource, time lag and MWh ratio parameters represent are dependencies that market participants with different resource ownership manage in today's market. The design does not preclude market participants from using the same mechanisms they use in today's market to manage operational challenges associated with different resource ownership in the future market. Forbidden regions are exclusively defined for hydroelectric resources in today's market. The design does not propose any changes to this definition for the future market. The offer floors for flexible nuclear and variable generation resources used in the current market are designed to manage dispatch order for reliability purposes under global and local surplus conditions. The future market design does not require a different dispatch order to manage reliability. Page 22 of the design will be updated to clarify that solar resources are also subject to the -$3 offer floor.

ID	Design Document	Stakeholder	Feedback	IESO Response
494	Offers, Bids, and Data Inputs	Power Advisory	Section 3.5.2 – Pricing Inputs: Constraint Violation Penalty Curves The Consortium acknowledges the need for IESO to work with MPs and stakeholders to establish various constraint violation penalty curves. […] Because the form of constraint violation penalty curves will be different within respective calculation engines in DAM, pre-dispatch, and RTM, more details are required to inform MPs and stakeholders on IESO's application of all constraint violation penalty curves – in particular which ones can set LMPs, how LMPs will be set when such constraint violation penalty curves are applied, and when IESO can relax constraint violation penalty curves so as they will therefore not set LMPs. It is acknowledged that the forthcoming Calculation Engine draft detailed design documents may contain these needed and important details. […] […] the Consortium is still of the opinion that price fidelity is important and therefore IESO should implement shortage/scarcity pricing for energy and OR within MRP and consider implementation of an OR Demand Curve (ORDC).	Table 3-7 in the Offers, Bids and Data Inputs design document describes the construct for each curve and the historical pricing methodologies that will be used to determine the values for each curve. The actual values that will be used for the future market will be determined during the implementation phase of the MRP. All of the constraint violation penalty curves used for pricing are eligible to set LMPs, even if the curves are relaxed. The DAM, pre-dispatch and real-time calculation engine detailed design documents define when the curves are applied in the engines and how LMPs are set (Sections 3.6.2 and subsection 3.6.2.2 for each document). The purpose of the constraint violation penalty curves described in Table 3-7 is to establish shortage prices in the future market that are at or below the current maximum market clearing price of +2000. The constraint violation penalty curves for operating reserve described in Table 3-7 is an operating reserve demand curve (ORDC).
498	Offers, Bids, and Data Inputs	Power Advisory	Section 3.5.6 – Demand Forecasts […] more clarity and transparency are needed regarding the methodologies to derive demand forecasts and IESO's application of demand forecasts within the DAM, pre-dispatch, and RTM calculation engines, along with rules and protocols when IESO can intervene and adjust demand forecasts.	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. Additional specificity about how the IESO arrives at the non-dispatchable load demand forecast from the total demand forecast for each area can be found in the DAM, pre-dispatch and real-time calculation engine detailed design documents (Sections 3.13, 3.11 and 3.11 respectively).