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 308 of the 506 comments that stakeholders submitted on the four detailed design documents. The IESO is still reviewing and considering the remaining 198 comments, and will response to those items in late November.

Contents

General Feedback

ID	Design Document	Stakeholder	Stakeholder Feedback	IESO Response
111	General	Association of Major Power Consumers in Ontario (AMPCO)	Currently, the most popular means for a Dispatchable Load (DL) to indicate its intent to operate as a Non-Dispatchable Load (NDL) is to withdraw its energy bids and accompanying Operating Reserve (OR) offers. […] None of the documents reviewed allowed for this process to continue with Market Renewal. Subsequent discussion between AMPCO and IESO staff indicated that this was a deliberate choice that they felt would benefit loads seeking to take a Day Ahead position as a non-dispatchable load. While we think there may be some limited benefit to this, it is greatly outweighed by the loss of the operational flexibility provided by the "No Bid" process to signal non-dispatchable status. Subsequently, IESO staff have indicated that they will provide consideration to returning this option to subsequent versions of the detailed design.	The no bid option for dispatchable loads will be retained in all three timeframes. The Calculation Engine design documents reflect the no-bid option. The Offers, Bids and Data Inputs and Grid and Market Operations Integration design documents will be updated to reflect the no-bid option.
112	General	AMPCO	[…] current IESO processes do not allow dispatchable loads to outage or derate their resource in the dispatch tools. Instead, loads manage these conditions through dispatch data, creating workload for the IESO and participant's operators, leading to incorrect dispatch and settlement outcomes and nuisance compliance allegations. Since generators have this ability in today's market, they have a clear advantage in handling temporary facility upsets over loads. […] The IESO has indicated in conversation they will not consider any improvements to this area until after the in-service date of the Market Renewal project. AMPCO disagrees with this approach. […] Unless the changes necessary are made now to the incoming toolset, AMPCO feels the IESO will not be able to make a business case to do so once the new market is in place.	The capability to evaluate load outages is not a standard feature in market software systems like it is for generation outages. The IESO considered the cost, effort, and impact to project schedules associated with customizing the engines to evaluate load outages, along with the benefit to market participants and the IESO. While this initiative is an important consideration to the dispatchable load community, it will not be included within the scope for the Market Renewal – Energy project.

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423	General	Capital Power	Unique Ontario Features Must be Taken Into Account The IESO is introducing a series of somewhat standard elements of market reform in Ontario – a market with highly unique and idiosynchratic features. Capital Power's concerns with this approach are largely set out in its comments on the Market Power Mitigation Framework, but the weaknesses inherent in such an approach to market design are arguably self-evident. When the vast majority [>80%] of supply in the IESO-Administered Market ("IAM") remains subject to rate-regulation or is under contract, it remains unclear what economic function the markets for energy and ancillary services serve. Without a clear articulation of the purpose of these markets when such a large share of economic and operational incentives are de-coupled from market prices, market performance cannot be measured and market failures will be difficult to remedy. This lack of clarity and transparency is of concern to Capital Power and should be addressed by the IESO as part of the MRP EDD. An additional section, for example, could be included in the next version of the draft to show how key detailed design choices reflect the unique features of Ontario and advance the broader MRP objectives.	The Market Renewal - Energy program is a series of projects that will deliver a more efficient electricity market. As indicated in the Business Case, the project will bring specific benefits that include enhanced reliability, greater operational certainty, increased system efficiency, addressing instances of gaming, and enabling future markets. The issues with the current market design have been well documented by the IESO, sector participants, the Market Surveillance Panel and others, and the ambitious push to renew the markets, guided by the advice of stakeholders, will lead to an efficient market design that benefits participants, ratepayers and the broader sector in Ontario.
424	General	Capital Power	Governance Framework Needs Enhancement When the MRP was launched in 2016, the IESO established principles to guide its design activities.1 As the MRP engagement progressed into detailed design however, the IESO did not demonstrate how it would objectively evaluate proposed elements and assess whether various design options would advance, or in fact undermine, these guiding principles. This has led to many remaining questions regarding not only how the proposed changes will affect market performance, participants and contracted assets, but it has also revealed deficiencies in the overall governance framework. Capital Power recognizes that the IESO has made efforts to improve its governance framework but believes that significant work remains to be done. As part of the next versions of the MRP EDD, Capital Power encourages the IESO to explicitly include i) how the changes meet the established principles; and ii) enhancements to the governance framework for new market elements.	The IESO has been, and is continuing to engage and respond to the detailed and constructive advice of stakeholders. Governing the path forward are the Market Renewal Mission and Principles, which articulate the five guiding principles of efficiency, competition, implement ability, certainty, and transparency. The IESO has taken measures to provide specific consideration of these principles when discussing changes to the design, and will look for continued opportunities to do so. Regarding the question on governance, the IESO has recently responded to stakeholder feedback recognizing a potential deficiency on how MPM disputes will be resolved, and will be engaging stakeholders later in 2020 with plans to enhance the governance framework for the renewed market.

ID	Design Document	Stakeholder	Stakeholder Feedback	IESO Response
425	General	Capital Power	Holistic Consideration of Market Design Is Required By defining how the proposed details meet the MRP objectives and principles as well as providing supporting analysis, the IESO could greatly improve stakeholder confidence and help ensure the overall market design continues to meet these expectations. This principle should apply to all IESO design initiatives, including the Resource Adequacy and Capacity Auction engagements. The adoption of such a framework and holistic consideration of how each of these fundamental elements work in conjunction with each other would also help to address two additional concerns: • Ongoing challenges related to the staggered release of design documents; and • Design documents lack necessary clarity needed to assess the probable impact of market reform on market and contract revenue streams. Capital Power appreciates the IESO's efforts to ensure the timely release of Detailed Design documents and its resassurance that stakeholders will have an opportunity to review collectively. A reasonable opportunity to consider all proposed design changes together is imperative so that stakeholders can identify interdependent issues and focus on providing targeted feedback rather than seeking additional information. Capital Power also emphasizes that stakeholder comments, questions and concerns will need to be revistited once all required information has become available.	The Market Renewal - Energy team will work to stay coordinated with other IESO initiatives that are affecting market participation, and there are internal processes in place to review potential interdependencies. All IESO initiatives are governed by the same Business Plan and Corporate Strategy. As indicated through various channels, we recognize the potential challenge stakeholders have faced with the staggered release of design documents, and are now provided with the opportunity to review prior feedback if it requires revision due to the publication of subsequent documents. The engagement for the detailed design, will result in a revised set of documents, transparency on the changes that were made to the design as a result of the feedback, and a list of outstanding items to be carried forward into another set of detailed discussions with stakeholders on the Market Rules and Market Manuals.
426	General	Capital Power	Ensure Reasonable Process for Contract Amendment Considerations Finally, as the IESO is aware, changes resulting from MRP will result in rule and manual changes triggering contract amendments. This fact only further amplifies the importance of clarity and transparency in the IESO processes, as well as the need for sufficient opportunities for stakeholders and contracted suppliers to conduct their respective reviews. Capital Power appreciates the IESO's efforts to proactively communicate its views to contracted suppliers, but suppliers must be given an opportunity to assess the impact of the proposed changes prior to the amendment process. In the context of MRP, this means that Design Documents need to be released with enough detail and time for stakeholders to effectively assess the impact of all MRP changes, taken together, on the contracts.	Thank you for your comment. The MRP Team will reiterate this comment to the Contracts team to work to resolve any differences in timing between these parallel processes.

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215	General	TC Energy	The following submission is intended to provide the IESO with TC Energy's view on areas of the detailed design documents that may need to be expanded or clarified in order to fully optimize the utilization of Pumped Hydro Storage (PHS) in the future IESO-Administered Market (IAM). […] Based on the following information TC Energy provides the following recommendations to the IESO: 1. Clearly define PHS in the draft detailed design documents. Describe how PHS is expected to operate in the market including changes initiated by the adoption of new market structures (e.g., DAM with binding financial schedules, pre-dispatch with unit commitments, and RTM operations). 2. Determine and describe situations where PHS resources will receive make-whole payments, such as when they are maneuvered for system reliability concerns. 3. Determine whether the current dispatch model accurately and economically reflects PHS resources. 4. State that PHS resources will be exempt from some uplift payments since energy storage is an intermediary resource, as announced in the IESO SDP.	The MRP Energy and Energy Storage Design Project initiatives, while not integrated within MRP, will continue to coordinate any updates as needed to reflect the interrelationship between the projects. Pumped Hydro will be modelled as a generation resource in the design for MRP - Energy.

Grid and Market Operations Integration

ID	Design Document	Stakeholder	Stakeholder Feedback	IESO Response
114	Grid and Market Operations Integration	AMPCO	The IESO has made it clear that it will not be providing any kind of improvements, or even enabling changes to the dispatchable load model that would allow dispatchable load to submit outage slips that would be acted on by Outage Scheduler and respected in dispatch. If this is the case, the sections on offers/bids during mandatory windows needs to consider dispatchable load switching back and forth between a dispatchable and non-dispatchable bid to facilitate operation during outage conditions. For example, -Section 3.3.7.5. describes changes to dispatch in the mandatory window. It needs an addition that would allow dispatchable load to submit a state change to non-dispatchable through their dispatch data for outage purposes. This would reflect the inability of dispatchable load to submit outage slips to manage their MW like a generator can. -Dispatchable load should also be able to re-establish dispatch data during the mandatory window for a return from outage/process upset, again since they cannot submit outages slips.	The IESO will update Section 3.3.7.5 to clarify that the treatment of dispatchable loads in the mandatory window will not change from today. Specifically, the ability for dispatchable loads to submit changes to and from dispatchable status within the mandatory window, and the process supporting this, will not change, as currently described in Market Manual 4.2 Appendix B section B.2.2.
123	Grid and Market Operations Integration	AMPCO	Section 3.4.2.5. Reliability Constraints only mentions generators as receiving manual constraints to support outage plans, reliability, etc. AMPCO discussions with IESO staff indicated that was meant to cover load facilities as well and will be amended.	The IESO will revise this section to clarify that the IESO may constrain any dispatchable resource to support outage plans, reliability etc. Dispatchable resources include generators, dispatchable loads, hourly dispatchable loads, imports/exports, etc.
470	Grid and Market Operations Integration	Capital Power	The ADE framework, has the effect of a must-offer requirement, and yet it will not apply to all resources. – There are benefits to a simple must-offer requirement, but the IESO is proposing to retain the ADE while also administering a complex ex-post mitigation framework targeted at physical withholding. The design, taken as a whole, presents inefficiencies that will place unnecessary administrative burdens and costs on both market participants (MPs) and IESO. If the IESO decides to move forward with the proposed Market Power Mitigation ("MPM") framework for physical withholding, any form of ADE must be necessarily flexible as capabilities and actual energy production will not be static and will frequently change due to prevailing conditions (e.g., ambient temperature, etc.). Offer quantities in the Day-Ahead Market ("DAM"), PD, and Real-Time Market ("RTM") will change based on these conditions. Therefore, considering the planned introduction of ex-post physical withholding MPM, there may be excessive administrative communication requirements between Market Participants and IESO regarding actual ADE quantities and their application to expost physical withholding.	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.

ID	Design Document	Stakeholder	Stakeholder Feedback	IESO Response
473	Grid and Market Operations Integration	Capital Power	Building on all comments made under 3.3.1 above, more details are needed regarding the triggers for when the IESO may request additional offers from generators that will permit energy and OR supply in RTM greater than their respective facility specific ADEs. This design element has the potential to reduce system flexibility and cause unnecessary administrative burden to the IESO and Market Participants.	There are no proposed changes to current triggers, and will remain consistent with those found in Chapter 7 section 12.2.2 of the Market Rules. The ability to solicit additional offers from generators is one of the control actions available to the IESO for reliability, and may be triggered by many different circumstances and conditions of the IESO or external control area. This action is included in the Emergency Operating State Control Actions list in Market Manual 7.1, Appendix B.1. In the event that the IESO needs to solicit bids and offers, the IESO will open the offer/bidding window and issue an advisory notice. Consistent with the current approach, the IESO will approve the submission of new or revised dispatch data that increases the ADE for dispatchable generation or dispatchable load facilities if additional bids and offers are requested. There is no additional administrative burden as market participants do not need to call the IESO in this case.
477	Grid and Market Operations Integration	Capital Power	The IESO has the ability to secure additional 30R to meet power system needs. When determined to be required, the IESO has proposed to schedule this additional 30R as an input in the DAM calculation engines. The IESO needs to provide more details regarding under what circumstances will the IESO secure additional 30R within DAM and how the market will be notified in advance.	Similar to today's notifications, the market will be notified in advance of the DAM of additional 30R requirements through the Adequacy Report and advisory notices. Market Manual 7.1, section 2.4.2 provides some conditions under which additional 30R may be required.
478	Grid and Market Operations Integration	Capital Power	The IESO allows itself the flexibility to constrain on a Combined Cycle facility in Single Cycle mode to allow it to start quicker. For the same reason a Generator should be able to offer in single cycle mode during the dispatch day without restriction to provide the market with greater system flexibility.	The calculation engines are only capable of evaluating pseudo-unit resources in either simple cycle or combined cycle mode across all hours of any look-ahead period. Hourly selection of modes is not possible. Market participants can still respond to market opportunities and offer their flexibility by changing to simple cycle mode intra-day, provided the pseudo-unit resource has no existing or future commitments in combined cycle mode. The IESO will continue to take any and all actions required to maintain reliability. This may include requesting a combined cycle plant to operate in single cycle or combined cycle mode. In such cases, the calculation engine will still require a single mode of operation for all hours of the look-ahead period.
480	Grid and Market Operations Integration	Capital Power	Demand forecasts are extremely important as they impact scheduling, prices, and dispatches. Due to the importance, more clarity is required around the rules for adjusting and overriding the demand forecasts.	The IESO's operators adjust demand forecasts in response to changing conditions on the power system. Operators first identify factors that influence prevailing conditions. Models are then updated based on these factors and a similar-day methodology is used to adjust generation to meet demand. More information about this method can be found in Market Manual 7.2, Appendix B.

ID	Design Document	Stakeholder	Stakeholder Feedback	IESO Response
481	Grid and Market Operations Integration	Capital Power	Hydroelectric generating units (particularly located on cascade river systems) will be afforded with increased flexibility regarding scheduling/dispatch and operations through new registration data and new dispatch data to be included within offer data […] Rationale for increased flexibility through additional facility registration data and offer data is to better respect regulations regarding water management and to therefore more efficiently schedule/dispatch energy and/or OR from applicable hydroelectric generating units (capabilities of generating units and overall market efficiency). However, the proposed new framework for quick start hydroelectric generating units is untested, as nothing like it exists in any other Canadian or U.S. wholesale electricity market (due to relatively smaller shares of hydroelectric generation), and it has potential to advantage applicable hydroelectric generating units while disadvantaging other resources […]. All other resources should be afforded the level of flexibility to ensure no one fuel or technology type is provided an unfair advantage vis-à-vis market design.	The new hydroelectric dispatch data parameters may only be submitted for foreseeable physical resource limitations that would be required to prevent the resource from operating in a manner that would endanger the safety of any person, damage equipment, or violate any applicable law. These physical limitations are currently managed through manual actions and are not intended to provide a competitive advantage.
483	Grid and Market Operations Integration	Capital Power	The issue illustrated in this section shows that a 20:00 EST PD run is too late for NQS generators to compete for off-peak hours of the next dispatch day. Unless the generator's status is hot, they cannot receive a schedule for HE1 in the next dispatch day. The fact that the IESO recognizes this for the purposes of reliability would indicate this time is too late and suggests reconsideration for the runtime is required	The timing of the 20:00 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.
247	Grid and Market Operations Integration	Electricity Distributors Association	Figure 1-1 appears to mistakenly reference the "Prudential Security Detailed Design" rather than the "Grid and Market Operations Integration Detailed Design."	Yes, the reference should be to the GMOI detailed design. The IESO will update Figure 1-1 in version 2 of the GMOI document.

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249	Grid and Market Operations Integration	Electricity Distributors Association	3.4.5 Demand Forecast Assessment and Adjustment We recommend that the Detailed Design be clarified by describing each type of demand forecast that is produced, the methodology for calculating each type of demand forecast, and how each type of demand forecast will be used in the scheduling processes and price formation. Further, we recommend that the IESO ensure that NDL demand forecasts are addressed in all sections that deal with demand forecasts. We were unable to find a discussion of either NDL demand forecasts or of how NDL demand forecasts will be used in the IESO's scheduling process(es). Whereas other documents, such as the IESO's Detailed Design on "Offers, Bids and Data Inputs", describes the production of NDL demand forecasts and other demand forecasts, section 3.4.5 of this Detailed Design document is silent on NDL demand forecasts. We recommend that the IESO comment on the process and methodology that will be used when producing demand adjustments that will be input into the PD calculation engine.	The IESO will produce hourly average, hourly peak, and five-minute demand forecasts for each demand forecast area. These demand forecasts will be representative of transmission losses and forecast consumption of all load facilities and hourly demand response resources in their respective demand forecast area. The methodology for determining NDL demand forecasts in each operating timeframe is discussed in the DAM Calculation Engine (Section 3.13), PD Calculation Engine (Section 3.11), and RT Calculation Engine (Section 3.11) detailed design documents.
326	Grid and Market Operations Integration	Northland Power	On Page 43 of the document (section 3.5.4.2), it states "In the DAM, cascade hydroelectric resources owned by the same market participant will be scheduled respecting their intertemporal dependencies represented by the linked resources, time lag and MWh ratio parameters. Each set of linked resources, time lag and MW ratio parameters will link a pair of resources on a cascade, defining the upstream and downstream resource, time and MW relationship between the two resources." Question: Can a participate decide daily whether they enable this linkage? What if this only is an issue during spring freshet when forebays are operated at top of range. If the rest of the year they are operated in the middle, then this is less of a requirement? Will this be auditable or must be approved by IESO?	Yes, a participant may decide to enable this linkage daily. The linked resource, time lag and MWh ratio parameters are daily dispatch data parameters that the participant may choose to submit or not submit for any given dispatch day. A resource must be registered as a hydroelectric cascade resource in order to submit these parameters.
327	Grid and Market Operations Integration	Northland Power	At the bottom of page 48, it states the following "In the future market, the first run of the PD calculation engine where hours for the next day will be hours evaluated will occur at 20:00 EST on the pre-dispatch day, approximately 5 – 6 hours after the DAM results are published." Question: If a resource has a registered lead time of 12 hours, then does this mean that if a resource was not scheduled in the Day Ahead Time frame, then the earliest that resource could get a schedule to come online is around 8-9 a.m.? What if a resource had a lead time registered up to the maximum currenly contemplated of 24 hours, then does this mean that a resource would not get a schedule for the next days until approximately 20:00 the next day? How is that considered for programs such as the Capacity Auction that would normally expect resources to be offereing in during the hours of 12:00 – 21:00?	Yes, if a resource with a 12-hour lead time does not receive a DAM commitment, the resource would not be able to get a pre-dispatch commitment until 08:00-09:00 at the earliest. Similarly, if a resource with a 24-hour lead time does not receive a DAM commitment, that resource would not be scheduled until approximately 20:00 the next day.

ID	Design Document	Stakeholder	Stakeholder Feedback	IESO Response
615	Grid and Market Operations Integration	Ontario Energy Association (OEA)	3.6.1 Timing of Pre-dispatch Scheduling Process - not running Pre-disaptch until 20:00 may eliminate non Day-Ahead committed NQS units from being committed for the morning ramp should there be a contingency post Day-Ahead process. A NQS resource with 12 hour lead-time will not be available until approximately HE10, well past the morning ramp. Running Pre-Dispatch earlier could produce more efficient unit commitment when many resources are cold, for example a cold winter Monday morning. The document indicates Daily Dispatch data transfer from Day-Ahead to Pre-Dispatch and Real-Time will occur at 20:00 in the current day. Will this result in the current day Daily Disaptch Data being overwritten by the next day's Daily Dispatch Data? Or do Pre-Dispatch and Real-Time processes recognize distinct dispatch days?	The decision from the high-level design (HLD) was for the initial pre-dispatch (PD) engine run for the next day to be run at 20:00 in the day-ahead (DA). We responded to feedback from stakeholders similarly during the enhanced real-time unit commitment (ERUC) HLD discussion. We have since engaged the dispatch scheduling and optimization (DSO) vendor and they have confirmed that the length of the PD look-ahead period has a direct impact on the solution time. The more hours that are optimized by the engine, along with the increased functionality of the engine (e.g. new hydro and pseudo-unit dispatch data), the longer the run-time will be relative to the limited time available. It is for these reasons a change to the timing of the PD run for the next day is not feasible. The current day daily dispatch data will not be overwritten by the next day's daily dispatch data. Daily dispatch data is submitted for specific dispatch days, and the PD and RT processes recognize distinct dispatch days. Dispatch data submitted and approved by the IESO on the pre-dispatch day (current day) for the next dispatch day will be included in the 20:00 pre-dispatch calculation engine run and will only apply to the distinct hour(s) and distinct day(s) for which it was submitted. The pre-dispatch calculation engine run that initiates at 20:00 EST is the first that will evaluate this dispatch data for all hours of the next dispatch day. Some exceptions to how PD uses daily dispatch data were identified in situations where schedules cross midnight. These exceptions are detailed in PD Calculation Engine.
616	Grid and Market Operations Integration	OEA	3.6.2.1 Reliability Commitments for NQS Generation Facilities Prior to 20:00 EST Pre-Dispatch Calculation Engine Run- how will the IESO determine which NQS unit to commit without running Pre-Dispatch?	In the rare situation that a contingency occurs after the DAM clears and cannot be resolved with the pre-dispatch engine run at 20:00, a reliability commitment may be required for the following day that was not scheduled by the DAM. 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. Market manual 7.2 Appendix C describes the IESO's method to assess generation and transmission adequacy. This method includes, among other things, an assessment of forecasted demand and assessment of available resources.
332	Grid and Market Operations Integration	Ontario Power Generation (OPG)	[...] Compliance aggregation remains an important mechanism used by hydroelectric stations to balance physical/operational constraints while following 5-minute dispatch. OPG is interested in understanding if the IESO is contemplating any changes to the existing rules around the utilization of compliance aggregation and recommends that any proposed changes be stakeholdered with market participants.	The IESO is not currently contemplating changes to the existing rules for compliance aggregation used by hydroelectric resources. If changes are proposed in the future, the IESO will engage with market participants and provide feedback opportunities.

ID	Design Document	Stakeholder	Stakeholder Feedback	IESO Response
333	Grid and Market Operations Integration	OPG	[...] Similar to current timelines, OPG recommends that ancillary service providers must submit regulation services availability data prior to 09:00 EPT (i.e. one hour prior to the DAM submission window). This would allow hydroelectric ancillary service providers to assess the most up to date conditions impacting their ability to provide AGC. Forecasting conditions for AGC requires upstream flow information involving other stakeholders/regulatory parties and assessing the most current flow conditions and expected schedules for the current day. This would allow the IESO until 09:30 EPT to communicate their acceptance of AGC schedules, which would leave market participants 30 minutes to revise corresponding offers to the DAM.	Ancillary service providers need to submit regulation services availability data by 8:00 EPT so that the IESO can respond with their automatic generation control (AGC) schedule by 9:00 EPT. Market participants will then have the opportunity to revise their DAM energy/OR offers until the DAM window closes at 10:00 EPT. The IESO is proposing to allocate more time for DAM offer revisions than what is currently in place for the day-ahead commitment process (DACP) because DAM schedules will be financially binding; and the impact of market participants not having enough time to revise their DAM offers is more significant than it is for the DACP.
338	Grid and Market Operations Integration	OPG	In the Grid & Market Operations Integration detailed design document this hydro parameter is referred to as "Linked Resources, Time Lag and MW Ratio" but in the Offers, Bids and Data Inputs detailed design it is referred to as "Linked Resources, Time Lag and MWh Ratio". The IESO needs to clarify which name is correct (MW or MWh) and be consistent across all of the detailed design documents.	Thank you for identifying this inconsistency. The correct name is MWh Ratio. The IESO will correct all incorrect instances of this term throughout the detailed design documents.
339	Grid and Market Operations Integration	OPG	[…] If the ADE is retained under the DAM, OPG believes the method for which ADE is determined and used for hydroelectric resources would need to be revisited. A methodology to incent hydroelectric resources to more accurately reflect their capability based on expected conditions at the time of offer submission rather than trying to ensure adequate ADE in real-time. If ADE is calculated based on DAM resource offers, an alternative solution would be to allow RT offers to exceed DAM ADE by a reasonable margin (similar to compliance deadband) to recognize variability of water conditions (e.g. head change MW) between DA and RT timeframes. This solution would also provide flexibility for nuclear resources that experience varying lake temperatures between DA and real-time (RT) that affect overall MW output. […] In the case of hydroelectric, a unit with ADE of 50 MW is currently restricted to an increase of 1 MW in real-time which is not representative of head based capacity changes. The IESO should increase the ADE deadband to 15% or 10 MW, whichever is less, to represent the unique characteristics of hydroelectric operation. Otherwise, market participants will take on additional risk of infeasible day ahead financially binding schedules to allow for head-based changes in real-time.	Thank you for this advice. The IESO will include this alternative proposal into the design, to increase the ADE RT allowance - the amount by which small increases to your ADE are currently allowed without requesting our approval. Today these increases must be limited to 2% of the ADE established in the DACP Schedule of Record, or 10 MW, whichever is less. This amount will be expanded to the lesser of 15% or 10MW. This expanded allowance is expected to provide additional flexibility for market participants with resources that experience variability in conditions between DA and RT timeframes.

ID	Design Document	Stakeholder	Stakeholder Feedback	IESO Response
340	Grid and Market Operations Integration	OPG	OPG recommends the IESO develop a process for evaluation and approval of ADE exceptions that has ease of implementation and places the least amount of burden on IESO control room staff. The reasons for requesting an ADE exception and receiving approval should be expanded to include: · changes to hydroelectric physical/operating constraints impacting head based capacity, · delays to an outage (transmission/generator) or a derate, etc. OPG suggests that IESO stakeholder a list of possible ADE exceptions during technical discussions with market participants.	The exceptions currently in place for ADE will not be expanded. These exceptions may not address every possible scenario that would require an increase to the ADE, but they do provide reasonable coverage. As an alternative to expanding the exception list, the IESO will increase the ADE allowance from the lesser of 2% or 10MW, to the lesser of 15% or 10MW. This expanded allowance will allow for increases to ADE without requesting the IESO's approval and will provide resources with additional flexibility. During Implementation the IESO will explore potential opportunities to further streamline the ADE evaluation and approval process, where practical.
342	Grid and Market Operations Integration	OPG	In section 3.4.1 the design states: "IESO data inputs related to reliability requirements, demand forecasting and centralized variable generation forecasts are made public to market participants through public reports and advisory notices. The timing of report publication is detailed in the Publishing and Reporting Market Information detailed design document. Advisory notices will continue to be ad hoc and present additional information not available through public reports." OPG recommends, the IESO consolidate reporting processes to include standard reporting and timing of the information that would be contained in an "Advisory Notice" into the Adequacy report. The report would populate when an "Advisory Notice" is issued and be empty for periods where there are no notices. This would allow market participants to automatically and easily retrieve and archive this data for analysis or reference. Formal reporting of "Advisory Notices" will increase transparency and efficiency after market renewal.	The IESO will bring forward this comment for consideration during implementation phase.

ID	Design Document	Stakeholder	Stakeholder Feedback	IESO Response
343	Grid and Market Operations Integration	OPG	In section 3.4.2 the design states: "Reliability requirements are operational inputs produced by the IESO to satisfy grid reliability and security standards as per NERC, NPCC and IESO market rules. As defined in the Offers, Bids and Data Inputs detailed design document, these reliability requirements are: · Maximum Import/Export Limits; · Net Interchange Scheduling Limit (NISL); · Lake Erie Circulation Forecast; · Minimum/Maximum Area Operating Reserve; · Operating Reserve Requirements; · Regulation Capacity Requirements; · Security Limits; and · Reliability Constraints." There is an opportunity to increase efficiency and transparency if the IESO were to consolidate similar information and publish the consolidation in the same reports. For example: Publish Maximum Import/Export Limits, Net Interchange Scheduling Limit (NISL), and Lake Erie Circulation Forecast in the one report, all Operating Reserve data in one report, and security limits and reliability constraints together in a separate report. This approach would allow a market participant to look at a one report for similar information instead of cross-referencing multiple reports.	The IESO will bring forward this comment for consideration during implementation phase.
346	Grid and Market Operations Integration	OPG	The design shows that the first PD run is performed at 20:00 EST, which is up to 6.5 hours after the DAM schedules and prices are published. […] OPG recommends advancing the first run of the PD to 18:00 EST. This would give market participants an additional 2 hours to modify their offers to ensure that schedules produced by the DAM engine runs are feasible and reflect operational capability in RT. […] From OPG's previously submitted comments during the high level design phase, a 20:00 initial pre-dispatch run does not provide opportunity for gas suppliers (unless they have a fuel transportation contract) to procure additional gas that may be required for the next day between HE1-HE15 should the pre-dispatch results identify the need. An 18:00 initial run would provide suppliers a minimum amount of time required to meet the North American Energy Standards Board (NAESB) ID3 deadline at 19:00 to procure any gas between 22:00 today and 9:00 tomorrow. OPG understands the IESO investigated four options to facilitate an 18:00 publishing of ERUC that would span the following day and determined that none of the options were workable. OPG recommends the IESO reconsider advancing the first run of pre-dispatch to 18:00 EST now that the software vendor has been acquired and there is a greater certainty around actual software capabilities. If facilitating an 18:00 publishing of ERUC is still not feasible, please provide the rationale on why it isn't possible.	As you've noted, the decision from HLD was for the initial PD engine run for the next day to be run at 20:00 in the day-ahead. The IESO responded to feedback from stakeholders similarly during the ERUC HLD discussion. The IESO has since engaged the DSO vendor and they have confirmed that the length of the PD look-ahead period has a direct impact on the solution time. The more hours that are optimized by the engine, along with the increased functionality of the engine (e.g. new hydro and pseudo-unit dispatch data), the longer the run-time will be relative to the limited time available. It is for these reasons a change to the timing of the PD run for the next day is not feasible.

ID	Design Document	Stakeholder	Stakeholder Feedback	IESO Response
348	Grid and Market Operations Integration	OPG	[...] OPG suggests the IESO include a zonal breakdown of the centralized variable generation forecast for each of the nine zones in the new market. Market Participants should have transparency with regards to the forecasted amount of variable generation in the respective zones where their resources reside. Potential deviations in forecasted variable generation could have significant impacts to market participant resources, particularly if they are providing generation in constrained areas. OPG suggests the zonal breakdown of the centralized variable generation forecast be included in the Adequacy report published two times per hour.	The Variable Generation Forecast Summary Report provides a total provincial forecast and zonal forecasts for variable generation. Note that zonal forecasts are only provided for zones where there are three or more facilities in operation. This reporting practice protects the confidentiality of market participant data and will continue in the future.
350	Grid and Market Operations Integration	OPG	[…] OPG recommends that if the IESO elects to produce demand forecasts on a zonal level in DAM and PD, the 5- minute forecast adjustment should also be done on a zonal level. […] There should be full market transparency on forecast changes including but not limited to demand response (how much and when and in which zones), and highly variable embedded generation (i.e. solar, wind, batteries, etc.) Full disclosure on these elements impacting zonal/global demand is needed for grid reliability and market participant decision making. OPG recommends this information be provided in the Adequacy report published two times per hour.	Producing 5-minute demand forecast adjustments at a zonal level is not feasible due to time constraints in real-time operations. As noted in the Publishing and Reporting detailed design document, the existing Adequacy Report will be revised to include demand for the four demand forecasting areas. This modification should provide the requested information. Embedded wind and solar generation will continue to be included in the adequacy report as a component of forecast demand. The report will continue to be published twice per hour for a dispatch day, and hourly on the pre-dispatch day for the next day.
351	Grid and Market Operations Integration	OPG	The design states: "In the future DAM, these actions will continue to be used with one exception: additional inputs and changes to dispatch data for the DAM will not be considered or requested by the IESO after the close of the DAM submission window unless there is an IESO tool failure. Therefore, to detect issues earlier and provide the opportunity for a market participant to re-submit dispatch data prior to the close of the submission window, the IESO will perform an early assessment to determine if sufficient dispatch data was submitted to satisfy the day ahead forecast demand." OPG is seeking clarification of when the IESO is planning on performing the early assessment. Also, when these issues arise, OPG recommends that all market participants are informed and given the opportunity to make changes to their DAM dispatch data.	The early validation to determine sufficient dispatch data will occur before the close of the DAM submission window. The IESO will establish this process during implementation. In the event that this affects all MPs then participants will be promptly informed in order to resubmit their dispatch data prior to the DAM submission window ending.
360	Grid and Market Operations Integration	OPG	[…] OPG is seeking clarification if minimum constraints applied in pre-dispatch will coincide with the first hour that a unit is scheduled at or above its MLP in the DAM financially binding schedule. For example, from Figure 3-20, it appears that the minimum constraint to MLP for MGBRT is applied starting at 09:00 which is the first hour where DAM financially binding schedule is at or above MLP. Also, can the IESO confirm that if a MP chooses to withdraw from their DAM Operational Commitment, the minimum constraint to MLP for a units MGBRT will not be transferred to the PD calculation engine? The design document should state how the calculation engines would handle instances of operational commitment withdrawal for NQS generators.	Minimum constraints for the MGBRT period will be applied in pre-dispatch beginning on the first hour that a unit is scheduled at or above its MLP in the DAM financially binding schedule. If a MP chooses to withdraw from their DAM operational commitment, the minimum constraint to MLP for a unit's MGBRT will be removed. Subsequent runs of pre-dispatch will no longer schedule the unit in respect of the minimum constraint.

ID	Design Document	Stakeholder	Stakeholder Feedback	IESO Response
361	Grid and Market Operations Integration	OPG	The design states: "In the future market, import and export schedules resulting from the DAM will be passed onto PD in order to inform scheduling limits for import and export offers and bids in the PD evaluation." If a market participant changes its intertie bids/offers after the release of the DAM schedule, OPG is seeking clarification on whether or not future PD run intertie schedules will diverge from the DAM schedule based on the economics of the revised offer/bid data? For example, a market participant is economically scheduled to export 50 MW to MISO in the DAM for HE8-HE16. In HE5 of the dispatch day, the market participant's lower its offer price such that it is no longer economic to flow its DA commitment. OPG recommends that all future hours of the next PD run reflect the revised offers for the DA committed, i.e. a 0 MW export schedule for HE8-16. Published reports for all future hours should reflect import and export schedules based on a market participant's latest offers/bids to increase market efficiency.	Market participants can make price/quantity revisions to intertie transactions that have been scheduled in the DAM, and PD will evaluate those revised prices/quantities but only up to the MW quantity that was scheduled by the DAM. Depending on the economics of the revised dispatch data the transactions may receive a different PD schedule. In the example you've provided, the 50MW export would be scheduled to 0MW for HE8--HE16 in the HE6 PD run. This will be clarified in GMOI V2. Regarding your question about reports: Inputs to reports for future hours will include the latest available schedules. If a market participant's revised bids/offers resulted in a different schedule than that received in the DAM, the revised schedule will be included in subsequent PD reports.
363	Grid and Market Operations Integration	OPG	[…] Additional information is required on the mechanics, structure and IT requirements of the automated notification of commitment provided by the IESO and how market participants will submit confirmation of ability to comply. Due to the limited time available to market participants to respond to the binding start up instruction, there is concern about the reliability of receiving and delivering timely confirmation and OPG recommends that IESO should also communicate binding start-up instructions verbally to market participants. In addition, market participants should notify the IESO verbally regarding their ability to comply with the start-up instruction. OPG is seeking further information on the consequences for failing to respond to the start-up instruction within the 15-minute window identified.	The automatic notification of commitment will be delivered to market participants in a timely and reliable manner. Specific details on the mechanics of the notification have not yet been established. This information will be established with stakeholder input during Implementation and communicated to market participants prior to Go-Live. Regarding verbal communication, it is anticipated that IESO notification of binding start up instruction, and MP confirmation of ability to comply, will be only through the tool. Verbal communication will be required if a participant is unable to comply with start up instruction, and may be required if there is a tool failure. Consequences for failing to respond to the start-up instruction within the 15 minute window will be consistent with non-compliance of any market rule or market manual. Advisory schedules in advance of the binding PD advisory schedule will provide information for market participants regarding anticipated PD commitments to ready their processes to respond within 15 minutes.
364	Grid and Market Operations Integration	OPG	[...]OPG proposes that the current rule for market participants to provide 2-hour notice prior to synchronization be eliminated. Market participant acknowledgement and confirmation of a binding start-up instruction should replace the current notification to synchronize rule.	Yes, the current rule for market participants to provide 2-hour notice prior to synchronization will be eliminated. See GMOI section 3.8.1 which says: "In the future market, the notification of a commitment or de-commitment will be initiated by the IESO and not the market participant. The IESO will issue binding start-up instructions for DAM and PD commitments and notifications of de-commitment to NQS generation units during the dispatch day."

ID	Design Document	Stakeholder	Stakeholder Feedback	IESO Response
366	Grid and Market Operations Integration	OPG	The current market rules require market participants to provide 1-hour notice prior to de synchronization from the grid. The new communication protocol cited in comment #34 should replace the market participant's current requirement to provide 1-hour notice prior to a de-synchronization.	The automated decommitment notification and response will replace the verbal 1-hour shutdown notice. We agree with your comment and will provide a clarification in GMOI v2.0.
371	Grid and Market Operations Integration	OPG	Figure 3-29 shows the binding commitment to extend is issued 30 minutes past the hour for an extension that occurs in the first PD hour. OPG would like some clarity around the process with regards to how these binding commitments will be communicated to MPs. Clear communication channels/processes are required to ensure MPs will be able to meet their commitments.	Binding commitments will be communicated to Market Participants via the confidential report "Pre-Dispatch Binding and Advisory Schedule Report" as noted in Publishing and Reporting Market Information Detailed Design Issue 1.0 (Section 3.3.5, Table 3-6, Report number 2).
378	Grid and Market Operations Integration	OPG	Market participant changes to ramp rates within the mandatory window should not require IESO approval given that they often need to be implemented with very short lead time.	The short notice change criteria in Market Manual 4.2, Appendix B will remain the same. All new and revised dispatch data submitted within two hours in advance of the dispatch hour must be manually approved by the IESO.
383	Grid and Market Operations Integration	OPG	In regards to the sentence of section 3.8.4: "During operating reserve activation, the IESO will only schedule additional reserve up to the 10-min reserve requirement as permitted by reliability standards." Does IESO still respect the MW ratio if the resource is linked to other resources via the linked resource, time lag and MW ratio parameter? For example, if Resource A and Resource B are linked with a time lag of 1 hour and the MW ratio is 1:1. And at 10:15, Resource A receives operating reserve activation (ORA) of 20 MW. Would Resource B receive extra 20 MW of dispatch at 11:15? OPG is seeking clarity on how ORAs will be modelled for Linked Resources.	Operating reserve activations are not modelled for linked resources. Linked resources parameters are hourly parameters designed for multi-hour optimization in the DAM and PD timeframes. They cannot be evaluated for intra-hour optimization in real-time. If an ORA for an upstream resource requires that the downstream resource generate a proportional amount of energy at some point during the current or next hour, the market participant can request the IESO apply a minimum constraint on the downstream resource, as they currently do in today's market.
385	Grid and Market Operations Integration	OPG	From the November 25, 2019 IESO Stakeholder Engagement regarding Constraint Violation Pricing, the IESO identified that operating reserve demand curves (ORDCs) will be introduced to determine settlement prices. The ORDC was not mentioned in the detailed design and OPG requests more details regarding the new design element introduced.	Operating reserve demand curves are mentioned in Table 3-7 of OBDI. 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).

ID	Design Document	Stakeholder	Stakeholder Feedback	IESO Response
387	Grid and Market Operations Integration	OPG	Section 3.8.9 states that off-market transaction will not be scheduled by the DA and PD calculation engines. OPG is seeking clarification on how this applies to segregated mode of operation (SMO).	Off-market transactions are not offered into the market like other imports and exports and economically evaluated by the DAM or PD calculation engines. They are manually scheduled through out-of-market mechanisms. The calculation engines do, however, use off-market transaction inputs to recognize that energy will flow across specified interfaces. This is important to ensure that scheduled intertie transactions and internal generation will not result in intertie limit or internal security limit exceedances. For segregated mode of operation (SMO), outage submissions are used to schedule the out-of-market SMO transaction. The decision to accept or reject SMO is made manually ahead of time, not scheduled by the calculation engine based on economic merit. If accepted, SMO outages, supporting transmission outages, and associated transmission limit and intertie limit changes are provided to the DAM and PD calculation engine as inputs to ensure schedules will remain within required limits. The Grid and Market Operations (GMOI) detailed design chapter will be updated to clarify that off-market transactions are not economically evaluated by DAM and PD calculation engines.
389	Grid and Market Operations Integration	OPG	The detailed design 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; and · SMO requests can only be cancelled by the generator to address concerns related to the safety of any person, damage to equipment, or violation of any applicable law (SEAL).” Under the current market, market participants can submit these requests up to two hours prior to the dispatch hour. The new restriction is prohibitive and limits the flexibility to operate in segregated mode in the new market. OPG recommends that current market timelines for SMO requests are maintained in the new market. Generators who wish to be scheduled in SMO in the day ahead market should be subject to normal DAM timelines (i.e. 10:00 EPT rather than 09:00 EPT). In addition, market participants with direct connection to an uncompetitive intertie (i.e. HQ) should be allowed to engage in SMO for reasons other than SEAL.	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 DA into RT 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. Likewise, cancelling transmission-impactive SMO for reasons other than SEAL would allow one market participant to directly effect transmission limits between the day-ahead and real-time market. This would give that market participant an ability to influence system limits unavailable to the rest of the market.
391	Grid and Market Operations Integration	OPG	[...] To ensure transparency in the new market, there should be a procedure/mechanism to notify market participants when the IESO includes incremental imports in the PD for system reliability.	Procedures will be developed for this process during the Implementation Phase of MRP.

ID	Design Document	Stakeholder	Stakeholder Feedback	IESO Response
500	Grid and Market Operations Integration	Power Advisory	It is challenging at this point in time to present more fulsome comments on the draft Grid and Market Operations Integration Detailed Design Issue 1.0, as not all the calculation engine draft detailed deign documents [...] have been released. [...]Therefore, IESO should expect and accept further comments to the draft Grid and Market Operations Integration Detailed Design Issue 1.0, after MPs and stakeholders have reviewed the aforementioned draft detailed design documents.	As discussed at the engagement sessions, stakeholders will have the opportunity to review and revise feedback once all draft detailed design documents are published. The project reached that milestone on September 30, so stakeholders have the opportunity to submit new feedback applicable to previous detailed design documents resulting from the three calculation engine documents until December 2.
501	Grid and Market Operations Integration	Power Advisory	[…] the Consortium understands IESO's proposed planned retention of the Availability Declaration Envelope (ADE) framework that will establish maximum energy quantities that dispatchable generators (including VGs (i.e., wind and solar generators) and applicable hydroelectric generators) will be permitted to produce in RTM. However, for VGs and hydroelectric generators, retention of the ADE framework may pose future risks post expiry of contracts. Regarding hydroelectric generators, IESO should permit energy production in RTM greater or less than respective ADE quantities. This will better enable hydroelectric generators to produce energy and supply OR in accordance with real-time conditions, where RTM energy production quantities should be aligned with available water to enable maximum capable energy production from hydroelectric generators, so long as they are economic in RTM.	Resources such as hydroelectric and variable generation who experience variability in their output from day-ahead to real-time will have some flexibility with the ADE. The IESO will permit an increase in the real-time offered quantity relative to the ADE quantity if the reason for the increase falls into one of the existing ADE exceptions. See Market Manual 9.4, Section 4.5.5.1 for details on the exceptions. In addition, the IESO will expand the allowance for resources to increase their real-time offered quantity relative to the ADE quantity. The current allowance of the lessor of 2% or 10MW will be increased to the lessor of 15% or 10MW. This expanded allowance will provide resources with greater flexibility to manage increased capacity as a result of real-time conditions. Note that the ADE will cap increases to offers in the RTM and does not prevent a resource from reducing its DAM offered quantity in the RTM.
503	Grid and Market Operations Integration	Power Advisory	Section 3.3.7.1 – DAM Dispatch Data for the Real-Time Market This section states that: "Dispatch data for specific facility or resource types that will not be included for evaluation in the IESO real-time market are: • … "The variable generator forecast quantity dispatch data parameter that was accepted for evaluation in the DA [day-ahead] scheduling process." For clarity purposes, does the above then mean that IESO will use their centralized forecast energy production quantities for VGs within their RTM processes to finalize dispatch instructions within RTM for respective dispatch hours and dispatch intervals? Presumably this will be the case if DAM offer data from VGs will not be used by IESO in accordance with RTM processes.	Yes, that is correct, the IESO will use the centralized forecast for PD and RT. The IESO does not use the market participant-submitted VG forecasts in the RTM.
513	Grid and Market Operations Integration	Power Advisory	Section 3.5.5.1 – Publish DAM Results Public and private reports developed by IESO for individual MPs will be produced for DAM results, in addition to other timeframes/markets (e.g., RTM). While IESO has provided some details of these reports in the Publishing and Reporting Market Information Detailed Design Issues 1.0, more details and engagement consultations with MPs will be required to finalize these reports.	Yes, further details on reports need to be established during the Implementation phase. Where practical, the IESO will seek market participant input on reports. Final report details will be shared with market participants well prior to go-live.

ID	Design Document	Stakeholder	Stakeholder Feedback	IESO Response
514	Grid and Market Operations Integration	Power Advisory	Section 3.6.2.3 – Determination of Hydroelectric Generation Facility Schedules in Pre-Dispatch This section states that "… the PD [pre-dispatch] calculation engine will respect each of the parameters [Forbidden Regions, Minimum Daily Energy Limit, Hourly Must-Run, Minimum Hourly Output, Maximum Starts per Day, and Linked Resources, Time Lag and MW Ratio] listed above in the same manner as the DAM calculation engine." The Consortium agrees with the above point and supports the new pre-dispatch design features to determine advisory schedules for hydroelectric generators in the pre-dispatch timeframe. However, as conditions change regarding water availability from the end of the DAM scheduling process through to the pre-dispatch hours, affected hydroelectric generators may necessarily require flexibility through the ability to submit updated offer data in pre-dispatch. This will improve the efficient scheduling and commitments for energy and OR supply in RTM from these hydroelectric generators. It will also increase market efficiency by improving utilization of these hydroelectric generators through effective water management. Some of the new dispatch data are not dynamic and will depend on prevailing conditions. For example, Time Lag can change depending on power flows. This is especially so on cascaded river systems.	Thank you for your comments. The design that governs the rules around revisions to dispatch data can be found in GMOI section 3.3.7.5 (hourly dispatch data) and 3.3.7.6 (daily dispatch data).
517	Grid and Market Operations Integration	Power Advisory	The Consortium believes SBG management and negative pricing may be issues post MRP implementation for the following reasons. […] Ontario experiences much more frequent negative pricing than any other North American wholesale electricity market […] […] LMPs within specific sub-zones in the Northwest and Northeast zones may continue to experience a significant number of hours of negative pricing. […]	Along with the many benefits of Market Renewal to increase efficiency and transparency, the detailed design includes a settlement floor to reduce the potential impact of exaggerated negative prices on market outcomes.

Market Power Mitigation

ID	Design Document	Stakeholder	Stakeholder Feedback	IESO Response
N/A	**Market Power Mitigation**	**N/A**	**Multiple stakeholders touched on the same key themes in their feedback responses.**	Thank you for taking the time to carefully review the Market Power Mitigation detailed design document and provide your thoughtful feedback. The IESO has recognized some common themes that emerged from stakeholder's submissions: a request for consideration of a dispute mechanism, more information on potential constrained areas of the grid, and additional details regarding reference levels and quantities. We would like to provide the following information on each. Dispute Mechanisms - The IESO is examining how MPM related disputes may be resolved. The IESO will carefully consider this important issue this fall, and look for ways to effectively engage stakeholders throughout that process. Constrained Areas - The IESO will use the data available to provide an assessment of what areas of the grid would be classified as a narrow constrained area (NCA). The information provided will be for illustrative purposes only and will not constitute a designation for use in the future market. The IESO will work to make this information available as part of implementation in Q1 2021. Reference Levels and Quantities – Further details regarding costs and methodologies for determining energy and operating reserve reference levels and quantities was provided to participants in August. We thank stakeholders for provided their detailed feedback on those materials. The IESO is currently reviewing that feedback and will update the reference level and quantity workbooks accordingly. The updated workbooks and IESO responses will be provided to stakeholders ahead of the technology specific sessions in October and November.
116	Market Power Mitigation	AMPCO	[...] this detailed design does not state explicitly that dispatchable load is NOT subject to market power price mitigation ex ante for energy. [...] This needs to be clarified. [...]	Submitted bids from dispatchable load resources will not be subject to mitigation as per the current market power mitigation framework. The IESO will add a clarifying statement to that effect in Section 2.2.4.

ID	Design Document	Stakeholder	Stakeholder Feedback	IESO Response
117	Market Power Mitigation	AMPCO	Throughout the document there are dollar values provided for triggers for testing and reference values to be used in the absence of MP provided data. The source of these values should be explained and justified. The IESO needs to be transparent about this, and must provide a process for updating them. Will this be in the market rules and subject to an amendment process? Or would it be a Board of Directors decision? How would changes be stakeholdered? Additional clarity in this area is required.	The proposed values and specific rationale for individual parameters were provided in pre-reading materials and discussed at the September 27, 2019 and January 23, 2020 technical sessions. The 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. The values for the conduct and impact tests will be in the Market Rules. Any proposed changes will use the Market Rule amendment process.
118	Market Power Mitigation	AMPCO	Section 3.12.4.2 is confusing. It isn't clear whether make whole payments as a result of a manual constraint for reliability are exempt from ex post mitigation or not, since the second paragraph talks about a number of exceptions which are "excluded". AMPCO does not understand whether this refers to being "excluded from mitigation", or "excluded from the reliability constraint exemption"? The language in this section requires clarification. [...]	Make-whole payments to suppliers for reliability constraints will be assessed through the settlement mitigation process. Dispatchable loads will not be subject to settlement mitigation for energy bids. The IESO will add clarifying language to this effect in section 3.12.4.2.
119	Market Power Mitigation	AMPCO	Section 3.13.1.2. describes details that will contribute to the calculation of a reference price, including for Operating Reserve which will apply to dispatchable loads participating in the OR markets. Not a single item detailed in this section is applicable to a load facility, yet the term "resource", which includes DL facilities, is used throughout. If this process is to apply to loads offering OR, more development to the design is needed.	The IESO will amend the definition of operating reserve reference level found in section 3.13.1 to clarify that it applies to both generators and dispatchable loads. For more information on dispatchable load operating reserve reference levels, the IESO has posted materials on the IESO MRP stakeholder engagement page for the August 27, 2020 session.
308	Market Power Mitigation	APPrO	Second, [...] if reference levels are not accurate and do not take into account actual costs then the conduct thresholds need to be more permissive in order not to unduly harm a generator [...] APPrO proposes that the IESO re-engage stakeholders on conduct thresholds after initial discussions have commenced on reference prices/costs.	Reference levels for each resource will be based on the short-run marginal costs of that resource. Further discussion of specific costs and how they are represented in reference levels are the subject of the reference level engagement.
309	Market Power Mitigation	APPrO	Third, there exists a potential for new obligations under market rules to conflict with contract obligations. For example, some contracts require a facility to offer all of its contract capacity (energy) in the DACP (i.e. a must-offer obligation). With market renewal, this will become a contract obligation to offer energy in DAM. There is no contract obligation relating to operating reserve, and accordingly contract capacity was set without regard to the potential of supplying operating reserve.[...] There will be times when it is not possible for a facility to meet its contract obligations if it is also required, under market rules, to offer operating reserve. The new market design must recognize that facilities have existing contractual obligations, and MRP cannot create a situation where it's impossible to meet both contractual obligations and market rules simultaneously.	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 methodology to determine the reference quantity for operating reserve 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 should be raised during the reference level/quantity engagement process.

ID	Design Document	Stakeholder	Stakeholder Feedback	IESO Response
310	Market Power Mitigation	APPrO	[...] APPrO encourages the IESO to adopt other processes which could include informational sessions with examples as to how the proposed market changes differ from the environment we operate in today.	Thank you for the feedback. The IESO will consider this input when formulating the engagement strategy going forward, and will work with stakeholders to provide information that has the highest value to the broader stakeholder community.
312	Market Power Mitigation	APPrO	Section 2.2 (Market Power Mitigation in the Future Market) Today, a resource that is constrained off for Energy to supply OR is indifferent as to whether it is being scheduled for energy or OR as they will be kept whole to their energy operating profit. Could the IESO confirm that the same will be true in the renewed market and that resources should continue to be indifferent as to whether they are scheduled for energy or being held back for OR [...]	The IESO can confirm this understanding. The real-time make-whole payment (RTMWP) encourages market participants to respond to their dispatch instruction. It considers the economic trade-off between energy and operating reserve as described in the comment and is designed so that the resource is indifferent as to whether it is scheduled for energy or operating reserve. Details on the RT MWP can be found in section 3.7.5 of the Market Settlement Chapter.
313	Market Power Mitigation	APPrO	Section 3.6 (Ex-ante Mitigation for Price Impact) The IESO is proposing that energy offers below $25/MWh and OR offers below $5/MWh will be excluded from economic withholding tests. In order for APPrO to determine whether this is an appropriate value, could the IESO please provide the rationale for setting the benchmark at $25/MWh and $5/MWh?	These no-look values are consistent with those used in other jurisdictions where mitigation frameworks have been in place for many years. The IESO will continually observe the performance of the MPM 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.
314	Market Power Mitigation	APPrO	Section 3.6 (Ex-ante Mitigation for Price Impact)What would be the criteria or trigger around revisiting the $25/MWh and $5/MWh to ensure it is still the appropriate benchmark?	The IESO will continually observe the performance of the MPM 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.
315	Market Power Mitigation	APPrO	Section 3.6 (Ex-ante Mitigation for Price Impact) In a jurisidicational scan provided in FTI's June 29, 2017 Module G MMP Appendix, it showed that in MISO and NY ISO, if located outside a constrained area, they use 300% or $100/MWh as the threshold for Energy. Could the IESO provide their rationale for proposing 200% for Ontario's BCA zone and what differences it sees between Ontairo and NYISO and MISO to necessitate a more restrictive threshold?	This threshold will be increased to 300% in response to stakeholder feedback. This change will improve alignment of the MPM framework to the MPM guidelines and current practice in other jurisdictions.
316	Market Power Mitigation	APPrO	Section 3.8 (Mitigation of Make-Whole Payment Impact) The impact thresholds for make-whole payments for the NCA/DCAs is the same as it is for a BCA. Could the IESO provide rationale why the impact threshold is not more permissive in the BCA as is the case in the impact thresholds for economic withholding?	A BCA and global make-whole payment impact threshold of 20% is more in-line with the IESO's stated guidelines and the practice in other jurisdictions. The IESO will adopt this new value in version 2.0 of the MPM design document.
317	Market Power Mitigation	APPrO	In the make-whole payment impact (for NCA, DCA and BCA) a conduct and impact test will be carried out when an NQS which was committed and has a positive congestion component greater than $0/MWh on any binding constraint. Has the IESO conducted any analysis to-date to show how often a committed NQS could potentially have a congestion component greater than $0/MWh? Analysis and rationale for the use of $0/MWh would be helpful to determine if this is the appropriate benchmark to use or if some other value greater than $0 should be considered.	Commitment costs such as start-up and speed no-load do not directly contribute to congestion costs. Therefore a $0/MWh threshold is necessary to identify whether a non-quick start resource may have market power (via its commitment costs) to resolve a particular constraint.

ID	Design Document	Stakeholder	Stakeholder Feedback	IESO Response
318	Market Power Mitigation	APPrO	Section 3.13 (Reference Levels) IESO indicates a cost-based methodology will be used to establish an "approximation" of each resource's short-run marginal costs. The establishment of reference levels should not be an approximation but it should accurately reflect a resource's costs. Otherwise if the approximation creates a reference level that is below actual costs anytime that resource may be mitigated it would be forced to operate at a loss. [...]	Reference levels for each resource will be based on the short-run marginal costs of that resource. Further discussion of specific costs and how they are represented in reference levels are the subject of the reference level engagement.
319	Market Power Mitigation	APPrO	Please explain why long-term costs are not included in the energy reference reference levels, and where does the IESO see these costs then being recovered? If Ontario continues to be fundamentally an energy only market and there are no external mechanisms/constructs to support "missing money", will all of this be revisited? [...]	Energy reference levels are intended to support efficient energy market outcomes. Such outcomes are achieved from offers representing short-run marginal costs. The IESO currently has an active discussion with stakeholders regarding resource adequacy.
320	Market Power Mitigation	APPrO	In section 3.13.1.2 the for the OR Reference Level there is no equation provided but it simply states "opportunity costs". Could the IESO please provide clarity as to how this will apply to different types of resources.	Details on operating reserve reference levels are provided in technology specific guidance documents for reference levels and reference quantities. Costs that are eligible to be included in an operating reserve reference level are any costs that increase when the supply of operating reserves increases.
397	Market Power Mitigation	Capital Power	[...] Capital Power's key concerns with the proposed MPM framework include: • A lack of specificity, clarity and governance regarding key MPM parameters such as the reference and threshold levels; and • Elevated complexity and restrictiveness potentially to the detriment of the price signal and stakeholders' ability to compete that would, in any case, result in an unnecessary amount of administration and costs; [...] With other relevant detailed design documents remaining to be published, all MRP changes have yet to be considered together.[...] Capital Power provides its preliminary comments on the detailed design sections of the MPM document but notes that these may change as new related information becomes available whether by clarification of the mitigation framework or other design elements.	Thank you for the feedback. The IESO encourages interested stakeholders to participate in upcoming technology-specific reference level/quantity stakeholder engagement sessions. The IESO welcomes input on MRP design, including comments and questions related to MPM after reviewing the three calculation engine documents.
398	Market Power Mitigation	Capital Power	IESO rules and manuals must clearly state that when resources pass the C&I and other tests (e.g physical withholding, make-whole payments, etc.) they will not be mitigated further. • The IESO notes that "[i]f all dispatch data parameters specific to a resource pass the conduct test no mitigation will be applied to that resource." (p.7, MPM EDD) Capital Power supports this design decision and recommends that this be made explicit in the draft rules and manuals for all mitigation-related tests.	The market rules and market manuals will clearly articulate the conditions that are required to be met in order for a resource to be mitigated. For clarity, passing the conduct and impact tests for ex-ante mitigation for price impact does not exempt a resource from testing for settlement mitigation or for physical withholding. The IESO will clarify this in the V2.0 of the MPM design document.
399	Market Power Mitigation	Capital Power	Competition-related terms must be defined. • [...] no IESO definition has been provided for the terms "competitive market" or "competitive market outcomes." Capital Power recommends that the IESO provide definitions for these terms so market participants have a clearer understanding of the IESO's expectations in these respects.	Competitive market outcomes are those that would result from open competition among participants free from barriers that restrict participation. Barriers in an electricity market can include physical system constraints such as transmission limits.

ID	Design Document	Stakeholder	Stakeholder Feedback	IESO Response
400	Market Power Mitigation	Capital Power	Clarity regarding constrained area thresholds required. •[...] Greater details should also be provided regarding how the constrained area thresholds are set. The IESO should work with market participants in determining these thresholds as some resources will be impacted to a much greater extent than others based on their location on the grid and based on the other competitors in their area. Capital power reserves the right to provide further comments when complete details are available.	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 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.
402	Market Power Mitigation	Capital Power	Exceptions for operational constraints unclear. These should be specified. • The detailed design lacks specifics on how resource derates and forced /planned outages are going to be considered as part of the framework. Capital Power recommends that these operational constraints not be considered as physical withholding as such conditions clearly do not fall within its definition. In any case, additional clarity is required regarding how derates and outages will be considered.	Details around determination of reference quantities is found in the materials published to support the reference level engagement.
410	Market Power Mitigation	Capital Power	Greater clarity required regarding conditions for reliability scheduling. Given that a resource will be subject to testing anytime it is scheduled for reliability, the IESO should clarify conditions for reliability scheduling.	For clarity, the mitigation framework will not alter conditions for reliability scheduling. As written in section 3.12.4, reliability constraints include all manual constraints with the exception of those: - resulting from IESO tool failures; or - including a proxy for economic selection in the scheduling process. For example, resources scheduled for operating reserve activations
411	Market Power Mitigation	Capital Power	Proposed financial threshold in the list of trigger conditions appears arbitrary. The impact thresholds for MWPs should align with the impact threshold for energy. • One of the trigger conditions for NQS resources is if it receives an unmitigated MWP for a commitment that exceeds $10,000. No details were provided in establishing this threshold.[...] • The IESO proposes to mitigate MWPs if the impact is 10% higher than using the reference level. This is inconsistent with and is more restrictive than the Price Impact threshold at 200% for energy. It is unclear why these are misaligned. Capital Power recommends that the IESO explain the rationale for the $10,000 trigger threshold and align the MWP impact threshold with that established for the energy impact test.	The $10,000 threshold was intended to represent a material commitment guarantee payment. The IESO agrees that rationale was not clearly provided for this value. The IESO will revise this threshold to $15,000. This represents the average per-start commitment payment in the IESO-administered markets. This means that only above average MWPs will be assessed for MWP price impact. The difference between price impact thresholds and make-whole payment thresholds is consistent with mitigation design in other jurisdictions.

ID	Design Document	Stakeholder	Stakeholder Feedback	IESO Response
414	Market Power Mitigation	Capital Power	Additional clarity required regarding the IESO-proposed physical withholding framework if retained. • The design document notes that the "IESO may apply a conduct test." The IESO should define the specific conditions under which the test would be conducted. Further, governance is required around this element to instill market participant confidence in the framework. • The proposed tolerance level of 5 MW under NCA or DCA conditions are set too tight giving the IESO discretion to test almost anytime. Thermal generators' thresholds, for example, can change by more than 5 MW on a daily basis to reflect ambient conditions imposing unnecessary administrative burden. • The design element excludes details on how derates and outages will be accounted. The IESO must provide details for these circumstances. • It is not clear how the proposed 1.5x settlement charge was determined. Capital Power submits that any penalty should be based on the actual, not its potential, effect on price.	Section 3.9 outlines the conditions that must be met in order for the IESO to be able to test a resource for physical withholding. 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). Details around determination of reference quantities is found in the materials published to support the reference level engagement. These materials include the fact that reference quantities can be seasonal to reflect changes in ambient conditions. The IESO looks forward to engaging further on determination of reference quantities during the reference level engagement. These materials also discuss treatment of outages and derates in relation to reference quantities. The settlement charge is based on the impact of the behaviour on market prices. It is designed to provide a disincentive to exercise market power via physical withholding. The IESO believes that a charge of 1.5 times the price impact provides this disincentive.
416	Market Power Mitigation	Capital Power	3.9.3 – Mitigation for Physical Withholding in the Operating Reserves Market This design element is unnecessary and should be removed. If kept, revisions are required for it to be workable. • Capital Power strongly opposes the proposed physical withholding framework for OR. First and foremost, OR participation should remain voluntary as explained at subsection 3.9 above. Should the IESO maintain this design element, the criteria must be revised as the testing conditions and parameters are too restrictive without justification. For example, if a resource has a reference level above $5 and price settles above $15/MWh, all eligible resources to participate are automatically tested. This will result in constant and unnecessary testing. The minimum constraint of 0 MW trigger is also too restrictive and will cause the same outcome. The local conduct threshold of 5MW or 2% combined with zero impact threshold is also too restrictive imposing significant ex-post settlement charge risk that grows with steep persistence penalties. There is also a potential governance issue as the criteria for setting minimum OR requirements rests with the IESO and is currently unclear. Lastly, further clarity is required for granting exceptions due to operational reasons.	Creating a physical withholding framework for operating reserve does not create an obligation to offer operating reserve into the market. Market participants that choose not to offer operating reserve are only at risk of being mitigated if competition was found to have been restricted, the resource failed the conduct test, and prices were impacted. The conduct and impact test thresholds in the design are consistent with those used in other jurisdictions as well as with the MPM guidelines published during high-level design. 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.

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418	Market Power Mitigation	Capital Power	Criteria for designating constrained areas requires more detail. • It is unclear why the IESO has determined that congestion in 4% of hours is appropriate for a region to be designated an NCA. Further, no details were provided regarding whether a volume threshold would be included in the assessment of these 4% of congestion hours. [...] Capital Power recommends that analysis developed to establish the constrained areas thresholds be provided for stakeholder review. • More detail should be provided regarding how the IESO determined that 0.02 was the appropriate Generation Shift Factor ("GSF"). [...] Capital Power recommends that the IESO provide any supporting analysis or rationale it relied on to establish this value. Given that this value may not be static, Capital Power also suggests that a process to review or amend the parameter be considered.	The threshold of 4% is consistent with that used in other jurisdictions. It represents an average of one hour per day in a calendar year that the region cannot receive additional power from outside of that area. When congestion occurs more frequently than this the risk that resources modify their offer behaviour to target these opportunities is relatively high. The 0.02 threshold is intended to identify the set of resources that are able to resolve a constraint. The IESO will continually observe the performance of the MPM 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.
419	Market Power Mitigation	Capital Power	More detail and stakeholder engagement required to properly establish cost-based reference levels for financial dispatch data parameters. • [...] Capital Power submits that the processes to determine fuel costs and opportunity costs are examples of items that are currently not sufficiently defined. Additional elements for discussion include: Default Value of OR o It is not clear $0.10 is appropriate. Further, without proper governance and rules around the establishment of reference levels, frequent disputes are likely. Opportunity to Update Fuel Costs Prior to Market Scheduling o Fuel prices change constantly and can be very volatile in the winter. The requirement for participants to notify the IESO of lower fuel prices is another example of the increased administrative burden.[...] If maintained however, more detail around the process is required. • The IESO notes that periodic review may be performed. Capital Power is supportive of regular review but suggests that a governance framework (including timelines and triggers) and a dispute processes be included.	The IESO encourages market participants to participate in the reference level engagement. During these sessions, information will be provided and discussed on technology specific reference level cost components and reference quantities. The value of $0.10/MW is a threshold based on materiality. If a market participant believes that it has operating reserve costs that are lower than $0.10/MW, then it does not need to provide supporting documentation. If it believes that its operating reserve costs are in excess of $0.10/MW, then it will be asked to support those costs with the appropriate documentation. This information is discussed in the recently posted reference level engagement materials. The IESO will remove the obligation to notify the IESO if fuel prices will be lower than is reflected in the reference level.

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420	Market Power Mitigation	Capital Power	More detail and stakeholder engagement required to ensure the proper calculation of reference levels. • Capital Power is encouraged that the IESO will undertake further stakeholder engagement on this design element as it requires much greater detail to establish each component in the calculation. Additionally, Capital Power is interested in details regarding the following: Pseudo Resource Treatment o The existing Pseudo Unit approach provides efficiency benefits as it enhances and aligns the dispatch of certain units relative to their operating capabilities. Aspect of this approach could be improved as part of the IESO design that would allow resources to participate without a loss of flexibility into the market. Capital Power reiterates it comments provided previously to the IESO in March regarding pseudo unit submissions.	The IESO encourages market participants to participate in the reference level engagement and provide input on pseudo unit reference level treatment during technology specific engagement sessions.
239	Market Power Mitigation	Emera Energy	Other than an NCA or DCA, how can a resource determine if they are in a constrained area prior to submitting offers?	The IESO will post NCA and DCA designations in advance of the day-ahead market and pre-dispatch scheduling for the day-at-hand. The IESO will also publish designations of Uncompetitive Interties publicly in advance of the effective date of designation. This detail will be reflected in Section 3.12.5 of the document. Other constrained areas (BCA, global) are outcomes of market scheduling.
240	Market Power Mitigation	Emera Energy	What is the purpose of MWP mitigation? If a generator passes conduct and impact thresholds for offers, is it not then deemed to be a valid economic offer? Under what circumstances is a generator likely to receive MWP mitigation when dispatch data tests are passed?	There is a fundamental difference between what the price impact test is assessing and what the make-whole impact test is assessing. The price impact test assesses whether prices were 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. These are different tests that can produce different results. Consider the following situation: A resource offering well-above its reference level could be scheduled in order to support reliability in a given area of the grid. In this situation the fact that a resource is offering above their costs does not impact market prices and the price impact test may not be failed In this scenario, the resource would still be tested for make-whole payment mitigation.
241	Market Power Mitigation	Emera Energy	3.6.2: Presumably the reference levels for each of the OR products could/will be different?	Operating reserve offer reference levels can be different across the three different classes of operating reserves where the eligible costs of providing different classes of operating reserves vary.

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242	Market Power Mitigation	Emera Energy	3.7.1.1 – Since only minimum load point (MLP) offers are used to determine commitment does commitment cost mitigation only mitigate energy offers up to MLP?	Dispatch data used for commitment cost mitigation includes start-up costs, speed-no-load costs and energy costs up to minimum loading point (section 3.7.1.1).
243	Market Power Mitigation	Emera Energy	•3.9 Physical withholding- How will the IESO differentiate the requirement to offer Energy and OR during circumstance where a generator may not be able to offer its maximum energy and OR simultaneously due to either contractual or equipment reasons?	Participants will be able to provide the IESO with information as to why the energy or operating reserve was not available to be offered before a settlement charge is issued. Please refer to Section 3.9.1.1 for information on how market participants are given an opportunity to make representations with respect to reference quantities. Reference quantities themselves can account for such restrictions if they are commonly experienced.
244	Market Power Mitigation	Emera Energy	Will market participants be able to view their reference levels in advance of submitting offers in all submission windows? Will failed ex-ante tests (non-financial and/or financial) be notified to the participant immediately (ie a warning or error upon submission)? What is the process to override if required?	Yes, market participants will be able to view their reference levels. This ability will partly depend on availability of certain input data (e.g. fuel prices). For non-financial reference level, participants will be immediately notified and the dispatch data will be rejected. For financial reference levels participants will be notified after they fail the price impact test. While there is no override process for mitigation section 3.15 of the design document outlines the process by which participants can disagree with the reference level that was applied. Additionally, the IESO is examining how MPM related disputes may be resolved. The IESO will carefully consider this important issue this fall, and look for ways to effectively engage stakeholders throughout that process.
245	Market Power Mitigation	Emera Energy	•Can you please confirm that an Energy Services provider for multiple separate customers would not be considered the Market Control Entity for the purpose of mitigation and/or conduct test?	The participation and authorization detailed design document will be amended to provide additional clarity on the criteria for determining market control entities
328	Market Power Mitigation	Northland Power	In section 2.2 it states the following "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, including Chapter 1, Section 10A – General Conduct or Section 11 – Information Disclosure." Question: What information will participants be able to rely on to know whether MACD has initiated an investigation or whether they view the actions by partcipants to be serious enough to justify a further investigation? Does the IESO plan on issuing any new guidance on how these types of instances will be dealt with by MACD? Has the IESO set a statue of limitations for it's Enforcement Group (i.e. MACD) to notify participants whether any actions are being investigated as part of a potential compliance infraction?	The market power mitigation design does not result in any changes to how the IESO assesses potential breaches of the market rules.

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329	Market Power Mitigation	Northland Power	In section 2.2.6 it states the following "The methodology to determine the reference quantity for energy will be consistent with that used in the Reliability Outlook to assess resource contributions to reliability. These reference quantities can be modified by active outages, de-ratings, external factors such as ambient temperature, humidity, water flow conditions and other resource specific considerations. Question: In the stakeholder engagements the IESO suggested that participants should not only ensure their energy offers reflect their true capability, but that the IESO expected resources to update their availability by way of derates every single hour if the capability of the resources changes. Can the IESO confirm whether its their expectation that every single resource should be updating their true capability by submitting derate slips for each resource every hour where ambient conditions affecting natural gas generators or head impact the capability of a hydroelectric resources impact output? Also, can the IESO clarify the methodology of what "will be consistent with that used in the Reliability Outlook to assess resource contributions to reliability" means? What exactly is the methodology that is applied today? Given that resources currently do not submit derate slips on an hourly basis to reflect ambient conditions, then is it fair to say that whatever the IESO has been receiving up to this point and maintaining its reliability assessment has sufficed and going forward the IESO isn't seeking for anything in addition to the methodologies that have been in place since market open?	MRP does not result in any changes to outage reporting obligations. The methodology for determining reference quantities has evolved since publication of V1.0 of the MPM design document. Market participants can refer to the reference level and reference quantities written guide for more information. The methodology for determining reference quantities for each technology is found in that document. This methodology will be discussed in detail during the reference level engagement.
167	Market Power Mitigation	OPG	OPG cautions the IESO to ensure the calculation engine's ability to perform mitigation testing does not negatively impact the ability to optimize day-ahead and pre dispatch schedules in a timely fashion. The running time of the mitigation module should not cause the IESO to abandon hydroelectric optimization parameters or other market efficiencies. If this becomes the case, the IESO should re assess the thresholds as well as re-open negotiations on reference levels.	The ex-ante mitigation framework within the calculation engines has been designed with consideration of its effect on solution time. For clarity, specific values of reference levels and conduct and impact thresholds do not impact processing time of the calculation engines.
168	Market Power Mitigation	OPG	At the January 23rd Technical Session: Physical Withholding, the IESO stated the trade-off functions for energy and operating reserve will remain the same as in the current market. Whereas the IESO's dispatch scheduling & optimization (DSO) algorithm may not change, introducing a market power mitigation framework that tests compliance of the joint-optimization outcome will affect market participant operations and further work needs to be considered in the design to avoid unintended market consequences. This includes the joint-optimization of energy and operating reserve, make whole payments, use of an operating reserve demand curve, outage slips for operating reserve, etc., as these design elements will affect the trade-off functions. OPG would appreciate further stakeholder discussion on these items and their impact on trade-off functions prior to negotiations on reference levels and quantities with the IESO. [...]	Thank you for the feedback. The IESO will address comments on the calculation engine detailed design documents as appropriate. The IESO has been working with stakeholders collaboratively through the Detailed Design discussion, to further the understanding of stakeholders, and provide background, clarification, and rationale where needed. Further, the IESO has focused on providing background and examples to stakeholders, both in writing and in various stakeholder forums, that answer specific requests. The IESO and stakeholders recognize that the transition to a renewed market can bring forward many requests for scenarios or examples on the impacts on participants, and the IESO will aim to respond to these requests that provide the greater value to the broad stakeholder community, and provide the greatest efficacy. Stakeholders are also encouraged to engage resources to provide them strategic advice on to navigate the nuances of their participation in the renewed market.

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171	Market Power Mitigation	OPG	At the January 23rd Technical Session: Physical Withholding, the IESO suggested that physical withholding will be measured in real-time using revenue metering. It is OPG current understanding that this is no longer being pursued by the IESO as it is no longer referenced in the detailed design document. Please confirm that this is the case [...]	The IESO confirms that metering data will not be used in the assessment of physical withholding.
174	Market Power Mitigation	OPG	[...] Hydroelectric resources can be energy limited and offers are used to reflect the opportunity cost of water in what is expected to be the most valuable hours. If these offers fail the conduct and impact test, the ex-ante engine automatically overrides the market participant's offers with reference prices. This could result in a sub-optimal dispatch schedule as reference prices may not accurately represent the opportunity cost of the water, as it is a dynamic value. [...]	The IESO has proposed a methodology to account for opportunity cost in energy reference levels for energy-limited resources. The details related to this methodology were provided as pre-reading to the August 27, 2020 stakeholder engagement session: Reference Levels and Quantities. We look forward to discussing this proposed methodology with stakeholders in Q4 of 2020.
176	Market Power Mitigation	OPG	OPG requests additional details on how fair market value of interties will be determined in order to set references levels, particularly in times of shortage.	As described in Section 3.10.1, the IESO will use an intertie reference level for assessing mitigation on uncompetitive interties. Interties not designated as uncompetitive will not considered by the mitigation framework. The intertie reference level is determined based on either the offer-based reference price or the intertie border price depending on the circumstances. The process of assessing mitigation on uncompetitive interties affords market participants with an opportunity to make representations regarding their offer or bid prices and provide alternative intertie reference levels if the market participant fails the conduct and impact test using the intertie reference level.
177	Market Power Mitigation	OPG	Please clarify what happens when a non-financial dispatch parameter fails the ex-ante conduct & impact test. [...]	When a non-financial dispatch parameter fails the conduct test, that dispatch data submission will not be accepted and a revised value will need to be submitted. The conduct thresholds and registered values will be known to market participants in advance. The validation process for non-financial dispatch data is described in Section 3.5 of the detailed design document.
180	Market Power Mitigation	OPG	For Table 3-5 to 3-27, the IESO should include a short description of the rationale for each conduct and impact threshold level. [...]	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 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.

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183	Market Power Mitigation	OPG	The design states: "Mitigation tests for price impact will be applied in the day-ahead market (DAM) and the pre-dispatch (PD) scheduling processes. If processing time permits, the IESO will also implement mitigation tests for price impact in the real-time dispatch (RTD) scheduling process. Whether this is possible will be determined in the implementation phase." If an offer has passed the mitigation tests in day-ahead and pre-dispatch runs, why would there be a need to implement mitigation tests in real time?	The real-time engine will not assess mitigation due to solution time considerations. Mitigation decisions that are made by the pre-dispatch engine will be carried forward into real-time. The detailed design document will be updated accordingly.
190	Market Power Mitigation	OPG	The OR conduct thresholds from Table 3-30, including $5/MW LMP minimum price criteria, are too low and will likely result in over testing. It is OPG's understanding the IESO is targeting a threshold that would result in testing only 10% of the time or less. Has the IESO performed analysis to predict the frequency of testing that these thresholds would generate (i.e. is it more than 10% of the time)?	The $5/MW OR offer no-look threshold is consistent with that used in other jurisdictions. The IESO is not targeting a design that results in a specific frequency of testing for mitigation.
199	Market Power Mitigation	OPG	Reference quantities used in Economic Withholding may need to be different than the reference quantities used in Physical Withholding. On page 54, the design states: "For an energy offer, the IESO will establish an energy offer reference level curve for each set of dispatch data values. This will include up to 20 non-decreasing values of the energy reference level to form a monotonically increasing cost curve. This energy reference level curve will be used for the conduct and impact testing of the price quantity pairs submitted by the market participant." Please clarify how the energy offer reference level curve will interact with the calculation of physical withholding reference quantity.	Economic withholding involves assessment of offer prices only. Physical withholding involves assessment of offer quantities without consideration for the price of those MWs. As a result, the determination of a reference quantity does not consider the reference level for a resource. The approach per technology type for determining reference quantities is found in the materials provided for pre-reading to the August 27, 2020 stakeholder engagement session: Reference Levels and Quantities.
211	Market Power Mitigation	OPG	While the use of the reliability outlook methodology may be suitable in terms of long-term forecasting, OPG does not believe it will be suitable for use in market power mitigation, particularly for hydroelectric in the short term (i.e. day ahead and real-time). Please provide more details on the elements of the Reliability Outlook Methodology that will be applied for market power mitigation and physical withholding.	The methodology for determining reference quantities has evolved since publication of V1.0 of the MPM design document. Methodologies that will be used to determine reference quantities are found in the materials provided for pre-reading to the August 27, 2020 stakeholder engagement session: Reference Levels and Quantities.

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213	Market Power Mitigation	OPG	The first paragraph of Section 3.15 states: "As discussed in Section 3.13: Reference Levels, the IESO will set the cost-based reference levels for financial offers in advance of the day-ahead market trading day. The IESO will provide market participants with an opportunity to update certain cost values that will be used to set the reference level for a resource prior to running the DAM, PD and the RT calculation engines as described in Section 3.13.1." OPG would like some clarity on how these reference levels will be reported and at what time. OPG proposes that Reference Levels are published prior to DAM submission deadline and hourly during the Pre-dispatch timeframe for market participants to review and update their offers/bids accordingly.	The IESO agrees that reference levels should be published in a timely manner. The timing for publication of reference levels will be determined following the reference level engagement. Timing of publication of reference levels will partly depend on when the inputs to the reference level formula are available to the IESO. The IESO looks forward to engaging in discussions on these topics as part of the reference level engagement.
229	Market Power Mitigation	Ontario Waterpower Association (OWA)	Market Power Mitigation (MPM) design is a major concern for hydroelectric because of anticipated challenge of setting reference prices/quantities that account for changing flows and opportunity costs. a. Setting reference level prices for hydroelectric will be challenging given the relationship between opportunity costs and available water. b. Setting reference quantities for hydroelectric will be challenging given that offer quantities rely on available head/flows. c. Ex-ante offer mitigation for economic withholding could override hydro offers causing operations not intended by MPs. This could compromise a MPs ability to manage its resources efficiently and to ensure compliance to operating limits. d. New physical withholding process will result in excessive Outage slip submissions, which will not be manageable by either MPs or the IESO. e. If a Generator is not scheduled in DA, it has no obligation to pass water other than what is needed for minimum flow requirements and meeting Water Management Plan (WMP) obligations. Thus, if water is not passed beyond these base thresholds, downstream Generators won't get any water and LMP goes up. f. The issue of "economic withholding" will be difficult to prove simply based on the fact that hydroelectric marginal pricing is more aligned with opportunity cost than a conventional fuel cost. This also plays, in part, into the "Energy vs Operating Reserve" discussion.	The IESO has created a methodology to account for opportunity cost in energy reference levels for energy-limited resources. It has also created a methodology to determine reference quantities for energy-limited resources. The details related to these methodologies were provided as pre-reading to the August 27, 2020 stakeholder engagement session: Reference Levels and Quantities. MRP has not modified the obligations around submission of outage and derates to the IESO. The methodology to assess economic withholding is not an investigatory process requiring proof. It is an automated framework based on the steps outlined in the detailed design document. When the stated criteria are met, mitigation is applied in the relevant calculation engine or settlement process. As discussed above, the IESO has created a methodology to account for opportunity cost in energy reference levels for energy-limited resources. We look forward to discussing this methodology with stakeholders this fall.

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282	Market Power Mitigation	Power Advisory	Clarity on Market Power Mitigation Roles and Responsibilities [...] the roles and responsibilities within existing areas of market surveillance and compliance, and the future market power mitigation framework, must be reviewed, clarified, and made transparent mainly between, OEB, MSP, and IESO (i.e., Market Assessment and Compliance Division (MACD) business units and non-MACD business units). For example, in order to create clarity and transparency, MSP mandate, as set out in OEB Bylaw #3 and #5, should be reviewed and may need to be amended, same for the OEB-IESO Protocol. [...]	The introduction of the Market Power Mitigation framework will not alter the current authorities of the IESO, MACD or the Market Surveillance Panel. The IESO, through MACD, will continue to enforce compliance with the Market Rules. The Market Surveillance Panel's responsibilities are the purview of the OEB.
285	Market Power Mitigation	Power Advisory	Section 3.4.2 – Conditions to Test for Mitigation for Price Impact, Section 3.4.3 – Conditions to Test for Mitigation for Make-Whole Payment Impact, and Section 3.12 Designation of Constrained Areas and Uncompetitive Interties The Consortium is supportive of IESO use of the mitigation conditions listed under Tables 3-2 and 3-3 to determine whether to launch a Conduct & Impact Test towards determining whether to mitigate for market power. [...] By and large, transmission constraints are dynamic and not static, as may power system conditions can change the impact of these constraints, for example: weather; energy flows; generation outages; transmission outages; changes in energy consumption; operating state of the ICG and application of IESO control actions; imports on specific interconnections; exports on specific interconnections; etc. For example, take the Dynamic Constrained Area (DCA) mitigation conditions for local market power relating to energy. [...] Consider a load pocket with a 200 MW daily average peak demand that is supplied by multiple transmission circuits and has a local 50 MW hydroelectric generator. If one of the transmission circuits is removed from service for a prolonged outage (i.e., a medium-term transmission outage), the transfer capability to supply the load pocket with the remaining transmission circuits would be reduced to 180 MW under normal weather conditions. The following points provide circumstances that could impact the DCA itself, and considerations for both IESO and potentially mitigated MPs. • Under normal weather conditions, 20 MW of the 50 MW hydroelectric generator would be able to exercise market power in the load pocket while the remaining 30 MW would continue to compete globally in the IAM. [...] • The DCA conditions could change throughout the medium-term transmission outage. For example, under extreme weather conditions assume that the transfer capability reduces to 150 MW. Under this situation, the whole 50 MW capacity of the hydroelectric generator would be able to exercise market power within the load pocket. This hydroelectric generator would need to understand the extreme weather attributes that impact the transmission circuits transfer capability (e.g., wind speed, dew point, ambient temperature, etc.) and how it would impact their energy offer strategy.	The IESO has noted your support for the mitigation conditions. The IESO has created a methodology to account for opportunity cost in energy reference levels for energy-limited resources. The details related to its methodology was provided as pre-reading to the August 27, 2020 stakeholder engagement session: Reference Levels and Quantities.

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			• Peak energy consumption in the load pocket could also influence DCA conditions.[...] Applicable supplying MPs would need to understand how frequently the load pocket consumption pattern changes and what conditions might influence these changes. Further, the load pocket demand pattern will also be influenced by other not directly related impacts (e.g., economic activity, etc.). How load pattern expectations are incorporated into DCA conditions must be described to MPs, so they can understand whether their facility (e.g., generator) may be deemed with the ability to exercise market power and potentially be mitigated. • Depending on the location of the load pocket, system conditions outside the load pocket could influence power load flow expectations that serve the load pocket. System losses, generation outages, and other transmission system outages could result in reduced expectations that global supply in Ontario could serve the load pocket, therefore increasing the likelihood of the transmission constraint becoming "binding". • MPs would need to understand how each attribute influencing DCA conditions interacts with each other. [...] • Finally, where a hydroelectric generator has been determined to be an energy limited resource, their offer prices may be relatively higher so as to reflect the value of limited energy. High offer prices can lead to market power mitigation without clear insight into how DCA conditions were determined.	
286	Market Power Mitigation	Power Advisory	Section 3.6 – Ex-Ante Mitigation for Economic Withholding [...] how reference levels will be determined and set, how long they are set for, when reference levels could change, and MP ability to dispute IESO's application of the Conduct & Impact Test including re-setting offer prices to respective reference levels, all need to be addressed well in advance of the planned MRP go-live date of 2023 and arguably before applicable amendments to the IESO Market Rules are finalized. [...]	Further discussion of specific costs and how they are represented in reference levels are intended to be the subject of the reference level engagement.

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287	Market Power Mitigation	Power Advisory	Section 3.6.1.3 – Global Market Power Mitigation for Energy Price Impact Regarding its definition under Section 3.3 in Table 3-1 on p. 16, global market power is defined as "Market power that can arise when competition is restricted because the IESO is unable to schedule incremental imports from other jurisdictions and energy and operating reserve supply conditions are limited". It is not clear why IESO has chosen to define global market power contingent on incremental imports for energy and OR for a few reasons. [...] For example, if energy is required in the northern zones and imported energy from New York and Michigan interconnections (located in the southern zones) are determined to be "incremental", then this incremental energy will most likely not meet the energy need within the northern zones due to congestion typically along the East-West transfer interface. This could also be the case if energy is required in southern zones east of the Flow East Towards Toronto (FETT) transfer interface, where incremental energy from the Michigan interconnection or the New York interconnection at Niagara coming from west of FETT may not be able to meet this energy need due to congestion at FETT. [...]It is not clear why IESO has proposed to only include the New York-Ontario interconnection and the Michigan-Ontario interconnection as designated Global Market Power Reference Interties. [...] On p. 26 under Condition 1 – Incremental Imports and under Condition 2 – Price, "shadow price" and "nodal prices" are used respectively. For clarity, do these terms simply equal applicable LMPs on the Ontario side of the respective interconnections? If so, "LMP" should be used for consistency as is the case with other draft MRP Detailed Design documents. In Table 3-9 on p. 26, dispatch data used as conduct thresholds referring to "start-up offer" and "speed no-load offer" do not make sense, as imports will not be permitted to submit three-part offers as dispatch data. Regarding the need to administer market power mitigation for the Quebec interconnections, please see comments under Section 3.12.5 – Designation of Uncompetitive Interties later on in this submission.	Global market power is contingent on incremental imports due to the fact that incremental imports from neighbouring jurisdictions with competitive wholesale markets can act as competition with a supplier(s) who may otherwise have market power in throughout the province. If the interties with New York and Michigan are able to facilitate incremental imports, then suppliers are less likely to be able to exercise market power province-wide. 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, the IESO has determined that New York (NYISO) and Michigan (MISO) satisfy the criteria listed above. The first and second scenarios described illustrates a local market power issue, not a global market power issue. In the first scenario, energy from the south of Ontario cannot serve load in the north of Ontario. This scenario is dealt with via other facets of the mitigation framework (BCA, NCA, DCA). In the second scenario, local transmission congestion prevents energy from the west of Ontario from serving load elsewhere. This scenario is also dealt with via other facets of the mitigation framework (BCA, NCA, DCA). Under Section 3.6.1.3 Condition 1, "shadow price" is with specific reference to the "NISL shadow price". Under Condition 2, "nodal" price is with specific reference to the "intertie border price" which is the nodal price at the Global Market Power Reference Interties, ignoring intertie congestion. When the conditions for global market power are met, domestic resources are tested for conduct and impact. Meeting these conditions does not result in testing intertie transactions. Intertie transactions are only tested for market power mitigation according to the process laid out in Section 3.10 Ex-Post Mitigation for Economic Withholding on Uncompetitive Interties.
288	Market Power Mitigation	Power Advisory	Section 3.6.2.2 – Global Market Power Mitigation for Operating Reserve Price Impact Comments above regarding Section 3.6.1.3 – Global Market Power Mitigation for Energy Price Impact also apply to Section 3.6.2.2. Specifically, for OR, it is further not clear why IESO is proposing to use imports as the test for the exercise of global market power because OR is very rarely supplied to IAM through imports.[...]	Imports are not assessed when determining if the conditions to test for global market power for operating reserve are met. As stated in Section 3.6.2.2, "the condition to test for global market power for operating reserve will be met when the unmitigated market clearing price of a class of operating reserve exceeds a threshold level of $15/MW."

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289	Market Power Mitigation	Power Advisory	Section 3.8.4 – Global Market Power for Make-Whole Payment Impact in the Energy Market Comments above regarding Section 3.6.1.3 – Global Market Power Mitigation for Energy Price Impact and Section 3.6.2.2 – Global Market Power Mitigation for Operating Reserve Price Impact apply to Table 3-21 on p. 36 regarding imports not being permitted to submit three-part offers relating to make-whole payment conduct thresholds and import dispatch data.	Occasions when the conditions for global market power for energy are met result in testing domestic resources for mitigation, not intertie transactions. Intertie transactions are only tested for mitigation under the conditions described in Section 3.10. All testing for mitigation for intertie transactions is on an ex-post basis. As described in that section, only intertie transactions on interties that are designated as uncompetitive can be assessed for ex-post mitigation.
292	Market Power Mitigation	Power Advisory	Section 3.9.2 – Mitigation for Physical Withholding in the Energy Market Starting in this section referring to the Resources Tested, Conduct Test, and Impact Test, and then in subsequent sections regarding IESO tests for physical withholding and other ex-ante market power mitigation tests, IESO has stated they "may" apply respective tests, whereas for the ex-ante tests for economic withholding IESO has stated they "will" apply respect tests. Why has IESO made this distinction? It can be interpreted that IESO's ex-ante application of respective tests appears to be subjective and therefore rendered to IESO's judgement when such tests are applied. Whether this is the case or not, more details will be needed regarding how IESO will make decisions to apply respective ex-post tests for the exercise of market power or not. [...]	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). This is not a concern for ex-ante mitigation as is an automated process that is included within the relevant calculation engines.
293	Market Power Mitigation	Power Advisory	3.12 Designation of Constrained Areas and Uncompetitive Interties Building on above comments from Section 3.4.2 – Conditions to Test for Mitigation for Price Impact and 3.4.3 – Conditions to Test for Mitigation for Make-Whole Payment Impact, IESO needs to establish clear and transparent processes to determine the designated constrained areas, including binding transmission constraints and load pockets, regarding definition, grid locations, magnitudes and impacts, and frequency of review and re-setting. Determining when transmission constraints are "binding" and therefore determining load pockets are dynamic undertakings – power systems are in no way static. As discussed in the above Section 3.4.2 – Conditions to Test for Mitigation for Price Impact and Section 3.4.3 – Conditions to Test for Mitigation for Make-Whole Payment Impact, for example, determining DCA conditions is a function of multiple variables influencing transmission constraints and load pockets. [...]	Specifics regarding the methodology for determining and establishing constrained areas will be provided to stakeholders as part of the development of market rules and manuals.

ID	Design Document	Stakeholder	Stakeholder Feedback	IESO Response
294	Market Power Mitigation	Power Advisory	3.12.1 – Narrow Constrained Areas As described in this section, IESO has defined Narrow Constrained Areas (NCAs) as "… areas where congestion is expected to be relatively frequent over a relatively long duration". IESO should provide examples of NCAs, [...]	The IESO will use currently available data to provide an assessment of what areas of the grid would be classified as an NCA. The IESO will work to make this information available as part of implementation in Q1 2021. The information provided will be for illustrative purposes only and will not constitute an NCA designation for Market Renewal go-live.
295	Market Power Mitigation	Power Advisory	3.12.1.1 – Designated Criteria It is reasonable for IESO to review NCAs on an annual basis. Details are needed regarding methodologies IESO will use to establish and re-establish NCAs. Further, if MPs do not agree with IESO established NCAs, a process for dispute and recourse needs to be defined. This section states that "… IESO has an expectation that a load pocket will be constrained in more than 4% of the hours in the following year in either the day-ahead market of the real-time market, the IESO may designate such a load pocket as an NCA". Why has greater than 4% of the hours for the following year been used to determine an NCA load pocket? [...]	Specifics regarding the methodology for determining and establishing NCA's will be provided to stakeholders as part of the development of market rules and manuals. A process for dispute resolution for mitigation-related decisions is under consideration currently. The threshold of 4% is consistent with that used in other jurisdictions. It represents an average of one hour per day in a calendar year that the region cannot receive additional power from outside of that area. When congestion occurs more frequently than this the risk that resources modify their offer behaviour to target these opportunities is relatively high.
296	Market Power Mitigation	Power Advisory	3.12.2 – Dynamic Constrained Areas [...] IESO needs to provide more details and clarity regarding what length of time or duration differentiates a binding constraint to be either an NCA or DCA. Further, IESO needs to provide more details and clarity regarding what magnitude of "increased congestion" will define the DCA load pocket. [...] Treatment of unplanned outages that create DCA conditions as well as communication protocols about system conditions and reliability response time expectation to MPs is required. In addition, other dynamic system conditions (e.g., load pocket consumption, power load flow expectations, etc.) will influence whether DCA conditions will exist. Interaction of dynamic system conditions with unexpected outage events that create DCA conditions must be clearly described to MPs.	Details regarding the designation threshold for DCAs are described in Section 3.12.2.1, including the specific timing thresholds that warrants designation as a DCA. DCAs are dynamic by design. They are intended to result in testing for mitigation while the relevant system conditions persist. For clarity, MRP does not result in any changes to how the IESO treats unplanned outages.

ID	Design Document	Stakeholder	Stakeholder Feedback	IESO Response
297	Market Power Mitigation	Power Advisory	3.12.2.1 – Designation Criteria This section states that "… IESO will determine the set of constrained areas of the transmission grid that meet any of the following conditions and may designate these as DCAs if: • The load pocket is import constrained in more than 15% of hours in a continuous five-day period prior to the current period in either the day-ahead market or the real-time market; or • The IESO identifies the prospective initiation of an outage or recurring conditions that previously caused a binding import constraint to a load pocket for at least 15% of hours in a continuous 5-day period in either the day-ahead market or the real-time market". Why has greater than or equal to 15% of hours in a continuous five-day period been used to determine a DCA load pocket?[...]	The value of this threshold is set based on other jurisdictions. Congestion occurring more frequently than this threshold over a short period increases the risk that market participants have significant incentive to alter their offer behaviour to exercise market power. The IESO did not identify the specific actions or outages that produce this frequency of congestion to determine the value of the threshold.
298	Market Power Mitigation	Power Advisory	3.12.3 – BCA Constraints This section defines a Broad Constrained Areas (BCA) as a specific area relative to a reference location where a resource(s) is "dispatched up" by IESO where an applicable transmission constraint creates a load pocket that binds relatively infrequently. This section goes on to state that "… BCA exists any time one or more resources outside an NCA or a DCA are scheduled with a congestion component greater than $25/MWh". IESO needs to provide more details and definition for determining BCAs. The proposed application of BCAs towards launching the Conduct & Impact Test will in part be triggered by IESO issuing dispatch instructions directing the resource (e.g., generator) to produce more energy than otherwise offered or was uneconomic for its supply based on its original offer. Therefore, if MPs are to be subject to market power mitigation resulting from following IESO's dispatch instructions where their resource happens to be located in an area coinciding with some form of transmission constraint, more details are required to properly comment on this aspect of market power mitigation.	BCAs are not determined in advance of dispatch. The list of resources that meet the BCA conditions (i.e. congestion component > $25/MWh) is a product of the relevant calculation engine. Determining congestion is carried out in the relevant calculation engine and considers market participant dispatch data, transmission limits and flows and other resource and system constraints.

ID	Design Document	Stakeholder	Stakeholder Feedback	IESO Response
299	Market Power Mitigation	Power Advisory	3.12.5 – Designation of Uncompetitive Interties [...] the Consortium suggests that given the number of radial interconnections between Quebec and Ontario that physically impede competition on these interconnections often rendering a sole MP with import or export transactions, than MPs as importers and/or exporters on these Quebec interconnections would appear to then be frequently under market power mitigation. IESO needs to also account for how transmission reservations are made and who typically owns these reservations – especially on the Ontario-Quebec interconnections. Considering history, very few MPs have dominantly held the supply of transmission reservations at the Ontario-Quebec interconnections. This could be an indication of the potential to exercise market power. Therefore, as stated earlier in this submission, all interconnections should therefore be accounted for under IESO's proposed global market power mitigation framework. Further, IESO has an existing contract with Hydro-Quebec23. Does this contract create an uncompetitive interconnection(s) between Ontario and Quebec with Hydro-Quebec having market power on this interconnection(s)? If so, how will this be reconciled with the position of applying market power mitigation on uncompetitive interconnections?	The detailed design document does not include designation decisions for uncompetitive interties. Section 3.12.5 provides a description of how uncompetitive interties will be designated. 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, the IESO has determined that New York (NYISO) and Michigan (MISO) satisfy the criteria listed above. Consideration of potential competitive impacts of contracts is outside the scope for the market power mitigation detailed design document.
300	Market Power Mitigation	Power Advisory	3.13.1 – Reference Level Methodology for Financial Dispatch Data Parameters [...] During the IESO led MRP stakeholder engagement meetings throughout 2018 and 2019, using opportunity costs to establish reference levels for renewable generators was discussed, yet there is no mention of this in the draft Market Power Mitigation Detailed Design Issue 1.0. Therefore, has IESO disbanded establishing reference levels for renewable generators based on opportunity costs? If so, can the IESO explain why? If not, more details are needed towards guiding how opportunity costs will be established for facility-specific renewable generators within the draft Market Power Mitigation Detailed Design Issue 1.0.	The IESO has created a methodology to account for opportunity cost in energy reference levels for energy-limited resources. The details related to its methodology was provided as pre-reading to the August 27, 2020 stakeholder engagement session: Reference Levels and Quantities. Further discussion of specific costs and how they are represented in reference levels are intended to be the subject of the reference level engagement.
302	Market Power Mitigation	Power Advisory	3.14.1 – Reference Quantity Methodology To establish facility-specific reference quantities, IESO proposes to determine reference quantities for energy supply consistent with those used in Section 4 of IESO's Reliability Outlook Methodology. [...] the Consortium believes there is more work to be done to effectively determine facility-specific reference quantities.	The methodology for determining reference quantities has evolved since publication of V1.0 of the MPM design document. This methodology was provided as pre-reading to the August 27, 2020 stakeholder engagement session: Reference Levels and Quantities. Further discussion of reference quantities is intended to be one of the subjects of the reference level engagement.

Market Settlements

ID	Design Document	Stakeholder	Stakeholder Feedback	IESO Response
N/A	**Market Settlements**	**Multiple**	**Multiple stakeholders submitted requests for examples, scenarios, and walkthroughs of the Market Settlements design.**	The IESO has been working collaboratively with stakeholders through the Detailed Design discussion to further the understanding of stakeholders and to provide background, clarification, and rationale where needed. Further, the IESO has focused on providing background and examples to stakeholders, both in writing and in various stakeholder forums, that answer specific requests. The IESO and stakeholders recognize that the transition to a renewed market can bring forward many requests for scenarios or examples on the impacts on participants, and the IESO will aim to respond to these requests that provide the greater value to the broad stakeholder community, and provide the greatest efficacy. Stakeholders are also encouraged to engage resources to provide them strategic advice on how to navigate the nuances of their participation in the renewed market.
121	Market Settlement	AMPCO	There are apparent contradictions on how the cost of demand forecast error will be treated. Page 23 says the zonal price for NDL will be modified to cover this cost. Page 69 talks about a "Load Forecast Deviation Charge" on NDL to cover costs. Then Page 94 talks about a "Province Wide per MW" charge that seems to be a forecast deviation charge that has two components that seem to be the exact same. We believe this topic would benefit from examples to provide clarity.	Thank you for your feedback. Load forecast deviation charge (LFDC) is the derived hourly province-wide forecast deviation dollar per megawatt hour ($/MWh) for the total cost of forecast deviation for non-dispatchable loads. This is comprised of two components: Real-Time Purchase Cost/Benefit and DAM Volume Cost/Benefit. The price paid by non-dispatchable load for energy withdrawn in real-time market will be the sum of the DAM Ontario price and Load forecast deviation charge (LFDC). The design document will be modified to use consistent terminology for the cost of demand forecast error throughout the design.
122	Market Settlement	AMPCO	The detailed design document does not always make it clear when amounts apply to dispatchable load as well as generators. Many of these scenarios can happen to loads as well as generators (e.g. make whole payments for IESO control actions like constraining on). The IESO needs to review all make whole payments formulations and include dispatchable loads where it is applicable.	Thank you for your comments. The IESO will review all make-whole payments and provide clarification where the make-whole payment applies to dispatchable load in the Market Settlement document.
427	Market Settlement	Capital Power	It is clear based on the scope and content of the draft MRP design documents that many amendments to the IESO Market Rules will be required, and some of these rule amendments may impact operations and revenues of some generators and trigger the need for contract amendments. The proposed settlement of the gas fired generators will create some fundamental disconnects with the deemed dispatch settlement logic within the CES-style contracts. The draft MRP settlements, while necessary under the construct of a financially binding DAM, unit commitment in DAM and PD, and three-part offers for NQS generators, poses significant potential implications to contracted gas-fired generators based on present direction to amend applicable contracts. Capital Power recommends engaging with contract holders and contract management during this detail design phase to reduce impediments to the implementation of an efficient and competitive market.	The process to review contracts, and discuss with contract counterparties is underway, and running parallel to the detailed design engagement. The Market Renewal - Energy project will work to stay aligned as the process to review contracts continues.

ID	Design Document	Stakeholder	Stakeholder Feedback	IESO Response
431	Market Settlement	Capital Power	More details and information are needed regarding the DAM Thresholds from the Market Power Mitigation Information System (see Table 3-13 in Section 3.5.4 – Collection of Day-Ahead Market Data, Table 3-22 in Section 3.5.5 – Collection of Pre-Dispatch Data, and Table 3-30 in Section 3.5.6 – Collection of Real-Time Data) relating to how IESO will derive and apply transmission constrained areas and their application to determining Make-Whole Payment Impact Test Thresholds.	Section 3.8 of the Market Power Mitigation detailed design document describes settlement mitigation. The information contained in this section for each type of settlement mitigation (BCA energy, global market power energy, etc.) include i) the conditions for testing; ii) the conduct thresholds applied; and iii) the make-whole payment impact thresholds applied.
432	Market Settlement	Capital Power	Further details and information are needed to properly review and assess Generator Failure Charges (see Table 3-26 in Section 3.5.5 – Collection of Pre-Dispatch Data). Presumably more details will be provided in the forthcoming draft detailed design documents relating to calculation engines (i.e., (i.e., Day- Ahead Market Calculation Engine, Pre-Dispatch Calculation Engine, and Real- Time Calculation Engine). Overall, examples from IESO will help provide clarity as to how new settlement design components are proposed to work.	Thank you for your feedback. The DAM Calculation engine detail design and Real-Time Calculation engine detail design are currently available for stakeholder review and stakeholders will have an opportunity to provide additional feedback once all detail design documents are posted.
433	Market Settlement	Capital Power	Table 3-10 indicates a separate DAM_LMP for Steam turbines and Combustion Turbines. o Is it possible for different resources at the same facility to have different LMPs? o How would this impact dispatch?	LMPs will be determined at specific resource locations on the IESO grid. As combined cycle facilities are a combination of two multiple resources, the LMP of each resource can differ slightly. This could occur if the CTs and ST are connected at different connection points to the IESO-controlled grid; affecting the marginal cost of losses and congestion at each resource. As today, a resource's location on the IESO-controlled grid is considered when schedules and dispatch instructions are created. The resource LMPs themselves do not affect dispatch; they are a result of the optimal dispatch.
436	Market Settlement	Capital Power	There is some discrepancy as to what "implied" costs are. The applicable reference in this section (3.7.1) states that "This means that the costs eligible for recovery may not be the actual costs. The cost eligible for recovery will be the cost implied by the offer, subject to mitigation." Please clarify.	The cost of production is represented by the offers submitted by market participant and may be subject to mitigation. In the event that the offer costs are mitigated, the costs eligible for recovery will be based on the mitigated offer costs and not the costs submitted by the market participants. Section 3.6 of the Market Power Mitigation detail design provides further details on the mitigation of dispatch data for energy and operating reserves.

ID	Design Document	Stakeholder	Stakeholder Feedback	IESO Response
437	Market Settlement	Capital Power	Eligibility rules for Recovery of Implied Cost of Start-Up are too restrictive. [...] The IESO should consider relaxing this requirement. Furthermore, with respect to the recovery of SUC, one of the eligibility criteria for a PSU is "The combustion turbine's simple cycle flag is not activated during its minimum generation block run time." – the start-up cost is based on the CT. If the CT starts up and runs, then it should be eligible for SUC, regardless of whether the ST fails to ramp. This applies to both RT and DA GOG	DAM will only commit a resource to meet system needs. If the resource is not available in real-time, it can have significant impact on reliability and may require the commitment of a more expensive NQS generation unit to meet system demands. The eligibility rules of requiring the unit to be available in real-time eliminates the undesirable outcome of the market paying start-up costs twice and reduces the risk of system reliability. The start-up cost and SNL cost components of the DAM GOG are not subject to the financial binding schedule, therefore, not exposed to the real-time balancing charge. If a resource comes offline before the MGBRT is completed, it will not be eligible for start-up costs compensation. The start-up cost is evaluated over the minimum of the MGBRT period to determine if the generation unit is the optimum solution for the overall period to meet system needs. If the resource does not complete its MGBRT, the market may incur additional cost in order to fulfill the remainder of the commitment period. Pseudo-units are committed based on the combined cost of ST and CT. If the CT comes online and completed its MGBRT, the CT will be compensated the start-up cost based on the CT to ST portion even if the simple cycle mode was activated during MGBRT and ST failed to come online. However, the failed ST would not be eligible for compensation of the start-up costs. This applies to both RT-GOG and DAM-GOG. The IESO will clarify the DAM-GOG eligibility rules in v2 of the detailed design.
439	Market Settlement	Capital Power	The NOD process has been largely unchanged from the current process. Considering the significant increased settlement complexities within MRP this framework should be reviewed. Capital Power may want to comment further on design element once more MRP details are released and reviewed	As discussed at the engagement sessions, stakeholders will have the opportunity to review and revise feedback once all draft detailed design documents are published. The project reached that milestone on September 30, so stakeholders have the opportunity to submit new feedback applicable to previous detailed design documents resulting from the three calculation engine documents until December 2.

ID	Design Document	Stakeholder	Stakeholder Feedback	IESO Response
251	Market Settlement	Electricity Distributors Association	As a general comment for the Market Settlement Detailed Design, we suggest that the IESO use consistent terminology. Throughout the Detailed Design the IESO uses several terms without standard definition, including: • DAM Zonal Locational Marginal Price of Energy • Real-Time Zonal Marginal Price of Energy • DAM hourly zonal price • DAM zonal price • Day ahead market prices • Ontario zonal prices • Hourly zonal LMP for the Ontario zone. For clarity throughout the Detailed Design and to help avoid confusion during the implementation phase, we recommend that the IESO carefully apply standardized defined terms, such as DAM Ontario Zonal Price and RT Ontario Zonal Price for province-wide uniform pricing, and DAM LMP and RT LMP for locational pricing at specific delivery points.	Thank you for your feedback. The IESO will update the design document to resolve inconsistency in the terminology for prices. The zonal energy prices determine by the DAM calculation engine within the Ontario zone will be referred to as DAM Ontario Zonal Price. The locational marginal prices in the Day-Ahead market will be referred to as DAM LMP.Similarly, the zonal energy prices determine by the RT calculation engine within the Ontario zone will be referred to as RT Ontario Zonal Price. The locational marginal prices in Real-time market will be referred to as RT LMP.
252	Market Settlement	Electricity Distributors Association	Section 2.1 – Market Settlement in Today's Market [...] We recommend that the IESO clarify that the descriptions provided in this section do not apply to either LDC customers or embedded generators that are not IESO market participants.	The IESO will update the detail design document to clarify that the detail design applies to registered IESO market participants.
253	Market Settlement	Electricity Distributors Association	Section 2.2 – Market Settlement in Future Market [...] We recommend that the IESO clarify that the changes articulated in this section apply to IESO market participants only. This section is the first example of the need to amend legislation, regulatory policy and regulatory instruments so that MRP's changes can be appropriately flowed through to LDC consumers and embedded generators that are not IESO market participants. This section should add that amendments will be required to the OEB codes (e.g., DSC, RSC, and SSSC, etc.) to correspond with changes to wholesale market pricing.	The IESO will make this clarification to the design. Further, the IESO will continue its work with stakeholders, including the regulator to gain a shared understanding of the interactive effects of changes to the IESO Market, and the corresponding changes that may be needed by associated policy, codes, standards and other instruments.
254	Market Settlement	Electricity Distributors Association	Since the Demand Response Auction has been replaced with the Capacity Auction, we propose that Figure 2-1 and Figure 2-2 be updated to reference the Capacity Auction.	References to Demand Response will be updated in V2 of the detail design to align with the new definitions in Chapter 11 of market rules.
256	Market Settlement	Electricity Distributors Association	Table 3-1 clarifies that the only settlement amount applicable to NDLs would be determined as part of the second settlement (i.e., Hourly Physical Transaction Settlement Amount – Non-Dispatchable Loads, or HPTSA_NDL). To be clear, the first settlement amount does not apply to NDLs.	The standard two-settlement (i.e. first and second settlement) does not apply to non-dispatchable loads. A modified settlement has been defined for non-dispatchable loads. Section 3.6.3 describes the settlement for non-dispatchable loads. The IESO will make the correction to Table 3-1 in V2.
257	Market Settlement	Electricity Distributors Association	We recommend that the IESO clarify that the final settlement statements that are provided 20-business days after the real-time trading day will provide the HPTSA_NDL to NDLs and that the IESO describe any changes in timelines and/or reporting. This will support LDCs in understanding the impacts of any changes to timelines and to reporting requirements.	HPTSA_NDL will be reported to NDL on their applicable preliminary and final settlement statements. All settlement statements will continue to be available on the IESO Reports site in the same format as today. Settlement statements will continue to be published according to the preliminary and final settlement timelines defined in IESO Settlement Schedule and Payments Calendars (SSPCs).

ID	Design Document	Stakeholder	Stakeholder Feedback	IESO Response
258	Market Settlement	Electricity Distributors Association	We recommend that the IESO also clarify how the IESO will report on the Load Forecast Deviation Charge (LFDC). We recommend that the IESO publish both the DAM Ontario Zonal Price and the LFDC as separate quantities, recognizing that the sum of these quantities will be the price applied to consumption by NDLs.	The Load Forecast Deviation Charge (LFDC) will be reported to market participants on the settlement statement for each trade day. Both DAM Ontario zonal price and the LFDC will be reported as separate amounts. More information on the reporting of LFDC will be provided during the implementation phase.
259	Market Settlement	Electricity Distributors Association	We note that LDCs will require guidance from the OEB on the methodology for distributing Congestion Rent and Loss Residuals (CRLR) to LDC customers.	Thank you for this comment.
260	Market Settlement	Electricity Distributors Association	[…] 1. We urge the IESO to provide more instructional information to market participants with respect to changes to charge types used in IESO market settlement processes. […] 2. We recommend that more detail be provided to assess the implications of any amendments that may be required to Table D-7. […] 3. We urge the IESO to provide more information on the processes and timelines required to implement the legislative or regulatory amendments flowing from the legislation related charge types that will need to be reviewed for potential amendments resulting from MRP. The list provided at Table D-9 includes 42 charge types that the IESO anticipates must be consulted on with the applicable regulatory bodies. We strongly encourage the IESO to augment this planned consultation to include LDCs and their customers as they will be impacted by these changes. 4. Appendix D should include an additional table that lists the OEB codes that will need to be reviewed and amended in advance of the implementation of MRP. […] This section implies that there will be a "transition period" when existing settlement amounts will appear on settlement statements alongside new settlement amounts. We propose that transitions should be planned and coordinated among all market participants so that old processes are phased-out in an orderly way.	Appendix D: Settlement Amounts, has categorized charge types by new and existing and is meant to provide a high-level summary. A brief description precedes each of these tables where additional information in the Detailed Design Document can be found. Specifically, more information on the existing charge types listed in Table D-5 can be found in Section 3.4 'Impact on Current Settlement Amount Calculations', Tables 3-3 (Replaced), 3-4 (Retired CMSC) and Table 3-5 (Retired DACP). Section 3.4 maps changes between current market settlement amounts and future market settlement amounts. All contracted ancillary service contracts will be reviewed and assessed under a separate initiative with the applicable contract holders. The balancing charges for contracted ancillary service contracts will continue to be applied on a pro-rata basis in real-time to loads and exports. The IESO will be engaging further with stakeholders and other sector partners to ensure that all relevant parties and all market participants are aware and prepared to respond to any changes that market renewal entails. With regards to the "transition period", the IESO will provide details of the transition between new/revised and existing settlement amounts as part of market participant readiness activities prior to go-live.
261	Market Settlement	Electricity Distributors Association	Section 3.5.6 Collection of Real-Time Market Data We recommend that the IESO clarify that the "interval" time resolution referred to in Table 3-27 is a 5-minute interval.	The IESO will modify the time resolution in Table 3-27 from "interval" to "5-minute interval"

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262	Market Settlement	Electricity Distributors Association	3.6.1 DA and RT Energy and OR Settlement: First Settlement We consider that this section provides suitable information with respect to the proposed first settlement. We note that the IESO proposes that market participants will continue to see Net Energy Market Settlement Credit on their settlement statements for a period of time. For the reasons set out previously, we propose that transitions such as the continued provision of certain information within IESO settlements, should be planned and coordinated among all market participants so that old processes are phased out in an orderly way. We repeat this comment with respect to the second settlement and notes that the IESO does not mention the need for a transition period in Section 3.6.2. We recommend that Table 3-40 be updated to include reference to the "electricity storage market participant". In general, the Detailed Design should be adjusted to include reference to the "electricity storage participant" per the Energy Storage Design Project, as applicable, since the interim design for storage is planned to be in effect prior to MRP. We also recommend that Table 3-40 clarify that LDC embedded generation facilities that are not registered with the IESO are not included in the "non-dispatchable generation facility" category. We propose that the IESO confirm that M1, as used in Formula Variant 2, applies to Price Responsive Loads (PRLs) without physical Hourly Demand Response (HDR) obligations, and that Formula Variant 2 does not use overlapping sets to set M1 and M2.	The IESO will communicate Settlement transition plans well prior to go-live. The MRP Energy and Energy Storage Design Project initiatives, while not integrated within MRP, will continue to coordinate any updates as needed to reflect the interrelationship between the projects. The design document will be modified to clarify that non-dispatchable generation does not include embedded generation that are not registered IESO market participants. The IESO can confirm that M1 represents PRL without physical HDR obligations and M1 and M2 do not overlap in Variant 2 formula for PRLs.
263	Market Settlement	Electricity Distributors Association	3.6.2 DA and RT Energy and OR Settlement: Second Settlement We consider that Table 3-47 should be revised in the same manner as Table 3-40 for consistency: • outline the eligibility for electricity storage market participants • clarify that "non-dispatchable generation" does not include embedded generators that are not IESO market participants • confirm that M1 and M2 are not overlapping sets for Variant 2. As well, Table 3-47 and Table 3-1, which describes the HPTSA_NDL as a second settlement, should be made consistent with each other, for example by clarifying that the HPTSA_NDL is part of the second settlement.	IESO will clarify that non-dispatchable generation does not include embedded generation that are not registered IESO market participants. The IESO can confirm that M1 represents PRL without physical HDR obligations and M1 and M2 do not overlap in Variant 2 formula for PRLs

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264	Market Settlement	Electricity Distributors Association	4.6.3 Non-Dispatchable Load Settlement We consider this section to be the single most economically impactful section to LDCs. It details the structure of the adjusted price that will be applied to electricity consumed by NDLs as the sum of the DAM Ontario Zonal Price and the LFDC. We find that the Detailed Design consideration of the adjusted price requires additional review and clarification. Consider the computation of the RT Purchase Costs/Benefit and the DAM Volumetric Factor Cost/Benefit that are required to determine the LFDC. Both factors require the DAM Quantity Scheduled for Withdrawal (DAM_QSW) for all non-PRL HDR resources at the specific delivery point. This value is not available for all non-PRL HDRs; non-PRL HDRs are permitted to aggregate contributors within an IESO zone, and the DAM_QSW does not specify the delivery point. To resolve this calculation the IESO will need to: • ensure that the DAM_QSW for all non-PRL HDRs is specific to the delivery point for all contributors, which will require a Market Rule amendment related to the participation of non-PRL HDRs or • make an assumption about the applicable delivery point(s) for all contributors of non-PRL HDRs, which risks affecting price formation accuracy.	The IESO does not require registered wholesale meter(RWM) for non-PRL HDRs in order to determine LDFC. The IESO will edit the LDFC formula to remove references to delivery point for non-PRL HDR resources. DAM Quantity Scheduled for Withdrawal (DAM_QSW) for non-PRL HDR resources will be determined by the DAM Calculation engine and used in the calculation of LFDC. More information on the DAM schedule for HDR can be found in Table 3-32 "DAM Scheduling output used to calculate the Forecast deviation per charge" of the DAM Calculation Engine detailed design document.
265	Market Settlement	Electricity Distributors Association	3.7.14 Congestion Rent and Loss Residuals (CRLR) We seek additional detail on the publishing and reporting of CRLRs (i.e., timing, communication). As noted elsewhere, the OEB will need to engage itself in this issue in a timely manner so that LDCs compensate their customers appropriately.	The Congestion Rent and Loss Residual Disbursement(CRLR) will be calculated on a monthly basis and provided to market participant on the settlement statements of the last trading day of each month. More information on reporting of CRLR will be provided during the implementation phase.
266	Market Settlement	Electricity Distributors Association	3.10 Regulatory Processes This section should add reference to OEB Codes that will need to be amended alongside MRP and accompanying regulatory and legislative changes. We consider that appropriate time must be provided for the Code amendment process and the stakeholder engagement that is required under the OEB Act. We recommend that both the IESO and the OEB collaborate to prepare a sound, balanced and disciplined stakeholder engagement plan to review and consult on all regulatory amendments and Code changes that would be required to implement MRP.	The IESO will make this clarification to the design, and will continue to work with stakeholders, including the OEB, so that all parties can understand and implement the changes needed as part of the renewal of the market.

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267	Market Settlement	Electricity Distributors Association	In general, we find that the IESO has identified the areas of the IESO market rules that will require amendment to affect MRP, with the following exception: Chapter 9, Section 6 (Existing – requires amendment) – Settlement Statements We consider that this section requires more specificity with respect to the required changes. Consider, for example, section 6.5.2 where the IESO states that HOEP will be replaced with "day-ahead market prices". As commented on in the Introductory Remarks, the IESO ought to use correct, specific and standardized terms to describe the prices referenced. This section should also reference the LFDC, because the price applied to NDLs consists of the sum of the DAM Ontario Zonal Price and the LFDC.	Table 4-1: Market Rule Impacts is intended to provide a summary of the changes to the market rules as a result of MRP and guide the development of the market rule amendments. The market rules and market manual will provide more specificity on prices.
268	Market Settlement	Electricity Distributors Association	5.1 Market-Facing Procedural ImpactsIESO Charge Types and Equations:We propose that the IESO plan the required consultation with the Canada Revenue Agency on the tax treatment for new or modified settlement charge types and also plan the follow on process for updating the Detailed Design documents, Market Manuals and Market Rules.	The IESO will consult the Canada Revenue Agency in determining the tax treatment for new and revised settlement and will incorporated the recommended tax treatment in the IESO Charge Types and Equations document which will be provided to market participants during the implementation phase.
269	Market Settlement	Electricity Distributors Association	Market Manual 5: Settlements, Part 5.5 - Physical Markets: We propose that Market Manual 5 reference both the price factor adjustment (i.e., LFDC) and the DAM Ontario Zonal Price. We recommend that the IESO's Market Manual include a new section on NDL settlement that is not subject to the two-settlement system.	The IESO will bring forward this consideration, and address during the Implementation phase.
270	Market Settlement	Electricity Distributors Association	File Format Specifications – Statement Files and Data Files: We consider that this section lacks specificity required by LDCs. As mentioned above and with reference to Appendix D, detailed information with respect to changes to charge types is required for LDCs to interpret how the reforms to the IESO market will impact existing LDC processes and settlements. We propose that the IESO provide worked examples and a schematic that maps changes from the current processes to new processes. We underscore the importance of including this level of detail in the Detailed Design phase, as opposed to later phases of MRP implementation, given that amendments to Market Rules and Market Manuals will be made based on instructions set out in the Detailed Design. Ambiguity in the Detailed Design increases the risk of increased complexity and uncertainty for LDCs during the implementation phase.	The IESO knows that the details of the settlement statement and settlement data files are important to the entire market participant community. While this level of specificity is challenging to address during the detailed design phase, much more information on settlement data files and settlement statements will be provided during the implementation phase.

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271	Market Settlement	Electricity Distributors Association	Training Material – Guide to Settlement Claims and Data Submissions via Online IESO (4.5 RESOP – LDC & Embedded LDC; 4.8 HCI Program; 4.8 FIT program – LDC & Embedded LDC): We consider that this section requires further detail and clarification. We assume that the IESO will continue to ensure full reimbursement of LDCs for the settlement of IESO contracts. This section states that the HOEP will be replaced with the "Ontario zonal price". As we have commented in the Introductory remarks, it is important to use clearly defined, standardized terms. We are unsure if the IESO is referring to the DAM Ontario Zonal Price or the RT Ontario Zonal Price in this section. Currently, distribution-connected generators that are not IESO market participants are paid HOEP for electricity delivered to the distribution system. Whether these generators are paid the DAM Ontario Zonal Price or the RT Ontario Zonal Price has consequences for LDCs that are responsible for settling IESO contracts. For example, if HOEP is replaced by the RT Ontario Zonal Price in the applicable IESO Contracts, there will be additional complexity for settlement because a "true-up" payment between the LDC and the IESO will required to reflect the difference between "DAM Ontario Zonal Price + LFDC" and the RT Ontario Zonal Price. Further, we note that the OEB determines the amount an LDC will pay to distribution-connected generator for injected electricity. We propose that the IESO consult with LDCs, in parallel with their consultations with generators on amendments to IESO contracts, to ensure that LDCs have complete information for settlement purposes and when communicating with customers.	The IESO will clarify this issue in the Detailed Design. Further, the IESO will take this comment forward into the implementation phase to be sure that stakeholders are engaged on the changes coming as a part of the renewed market, including the LDC community.
272	Market Settlement	Electricity Distributors Association	Training Materials - Settlement Statements and Invoices: We consider that this section lacks specificity and proposes that the IESO provide worked examples and a schematic that maps the changes from the current processes to future processes.	Table 5.1 was intended to provide a general summary of the impact of the detail design on the market procedures. More detail, including considerable engagement with stakeholders, will be provided alongside training materials well prior to go-live.
273	Market Settlement	Electricity Distributors Association	5.2 Internal Procedural Impacts We propose that the IESO establish a specific consultation process to focus on required changes to regulation and legislation, including OEB codes, as part of its collaborative review with the OEB.	The IESO is currently engaged with the broader stakeholder community, as it relates to changes required to policies, codes, standards. The IESO will work to provide timely updates to stakeholders on the progress on the interrelated required changes.
274	Market Settlement	Electricity Distributors Association	We point out that Figure 6-1 should be updated to refer to the Capacity Auction, rather than the Demand Response Auction. We point out that the IESO does not make reference to the LFDC in this section of the Detailed Design. This appears to be an omission.	References to Demand Response will be updated in V2 of the detail design to align with the new definitions in Chapter 11 of market rules. LFDC is a part of the NDL settlement calculation. The IESO will provide clarification in V2.

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231	Market Settlement	Emera Energy	In order to qualify for keep whole payments (DA_GOG) on SUC and SNL a unit must operate in RT. Typically once a facility clears a financially binding DA schedule it gets paid for all of its as offered costs, including any keep whole payments. Should a unit not deliver on its DA schedule it is subject to RT exposure in the form of buying back from the market, why have the IESO elected to tie the keep whole payments to actual RT performance. - The design documents indicate that a facility must complete its MGBRT to receive its SUC, should a facility trip offline during the last hour of its run does it not receive its SUC even though it has incurred this cost? - With respect to the recovery of SUC, one of the eligibility criteria for a PSU is "The combustion turbine's simple cycle flag is not activated during its minimum generation block run time." If the CT starts up and runs, then it should be eligible for SUC, regardless of whether the ST trips or not. This applies to both RT and DA GOG	DAM will only commit a resource to meet system needs. If the resource is not available in real-time, it can have significant impact on reliability and may require the commitment of a more expensive NQS generation unit to meet system demands. The eligibility rules of requiring the unit to be available in real-time eliminates the undesirable outcome of the market paying start-up costs twice and reduces the risk of system reliability. The start-up cost and SNL cost components of the DAM GOG are not subject to the financial binding schedule, therefore, not exposed to the real-time balancing charge. If a resource comes offline before the MGBRT is completed, it will not be eligible for start-up costs compensation. The start-up cost is evaluated over the minimum of the MGBRT period to determine if the generation unit is the optimum solution for the overall period to meet system needs. If the resource does not complete its MGBRT, the market may incur additional cost in order to fulfill the remainder of the commitment period. Pseudo-units are committed based on the combined cost of ST and CT. If the CT comes online and completed its MGBRT, the CT will be compensated the start-up cost based on the CT to ST portion even if the simple cycle mode was activated during MGBRT and ST failed to come online. However, the failed ST would not be eligible for compensation of the start-up costs. This applies to both RT-GOG and DAM-GOG. The IESO will clarify the DAM-GOG eligibility rules in v2 of the detailed design.
232	Market Settlement	Emera Energy	Can you please confirm that the MWP is intended to vaguely replace CMSC and is intended to balance situations where Energy or OR are constrained either up or down relative to an "optimal" dispatch.	CMSC is required in the current two-schedule market to account for differences between the constrained dispatch and unconstrained market schedules. CMSC is no longer required under the future single schedule market, where congestion is already reflected in both dispatch and market prices. When a resource is manually dispatched outside of its otherwise economic dispatch, they may be eligible for a make-whole payment.

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233	Market Settlement	Emera Energy	Can you provide more clarity around the settlement treatment of GOGs during things like trips or outages or other issues? - For example, can a generator return to service during its MGBRT and remain eligible for certain cost recoveries (as it can in the current PCG?) the wording of the SUC eligibility implies not, SNL is less clear.	A resource will only be evaluated for start-up cost compensation if the resource completes its full MGBRT. Resources will be eligible for energy and SNL compensation for the period where the resource is at or above its MLP. The IESO will reduce the implied cost of any speed no-load offer by 1/12th for each 5-minute interval where the generation unit did not produce energy for the full hour. If a resource comes offline during its MGBRT period and comes back online, the resource will not be eligible for start-up cost compensation. However, the resource will be eligible for SNL and energy cost recovery for hours where the resource is at or above MLP, including hours where the resource comes back online to fulfill the remainder of the commitment period.
124	Market Settlement	HQ Energy Marketing Inc. (HQEM)	HQEM would like to take the opportunity to comment on the Market Settlement Detailed Design. At the light of the information published, HQEM wants to make sure that a reasonable testing schedule and a sandbox will be available. Many participants are using automations to retrieve data linked to market settlement. Modification to acronyms and new uplift charges will need to be included in these automation, and this will take a several amount of time and ressources to modify current systems. Moreover, HQEM will be available to help and assist if the IESO needs participants to perform tests or validate system behavior.	Thank you for volunteering to assist in the test and validation of our systems. The IESO will provide more information on market trials to stakeholders prior to go-live.
524	Market Settlement	OPG	There are many linkages between market settlements and the day ahead (DA), pre-dispatch (PD), and realtime (RT) calculation engines. A comprehensive review of the settlement detailed design cannot be complete without the opportunity to review the calculation engine designs. OPG would like the opportunity to review and provide additional comments on settlements, as needed, following the review of the DA, PD, and RT calculation engine detailed design documents. The IESO's response to the Publishing & Reporting Detailed Design comments indicated that market participants will be given a second opportunity for comments following the release/review of the calculation engine design documents. OPG further suggests the IESO augments these comments with stakeholder sessions for market participants to discuss their recommendations and/or proposals with each other and the IESO.	As discussed at the engagement sessions, stakeholders will have the opportunity to review and revise feedback once all draft detailed design documents are published. The project reached that milestone on September 30, so stakeholders have the opportunity to submit new feedback applicable to previous detailed design documents resulting from the three calculation engine documents until December 2. The IESO will be posting all responses to stakeholder feedback for each design document and will publish a document to track all changes made to the first version of the documents as the result of stakeholder feedback (v1.0 to v2.0)

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525	Market Settlement	OPG	The application of "Settlement Floor Price" discussed at the Negative Pricing stakeholder session on February 13th, 2020 appears to be omitted from this design document. It is OPG's view that it should be included. At the Negative Pricing Stakeholder session the IESO stated: "To address this, the IESO is proposing a settlement floor of -$20/MWh. This settlement floor would define the minimum price that a market participant can pay or be paid for its injection or withdrawal of energy in the IESO-administered market. The settlement floor price would be used in all timeframes, meaning an hourly basis in the Day-Ahead Market and a five minute interval basis in the Real-Time Market." However, in the recently released Day Ahead Calculation Engine Detailed Design Document it states: "[illegible] shall designate the settlement floor price and be set equal to -$100/MWh;" This is inconsistent with the value that the IESO had proposed at the Negative Pricing stakeholdering session, and if the IESO is imposing a settlement floor price of -$100/MWh it should be appropriately stakeholdered with MPs. Please provide the rationale for this new amount and the reason for the change from the initial proposed figure.	The IESO hosted a technical session in February to discuss the settlement floor price with stakeholders. It was the discussion from that engagement meeting that influence the draft detailed design that has been posted. The rationale for the settlement floor price at -$100/MWh was provided at MRP Calculation Engine Technical Session on August 27, 2020. The presentation and recording is available for review on the Energy Detailed Design Stakeholder engagement page.
526	Market Settlement	OPG	There are many instances in the document where it is stated that a settlement amount is calculated for a facility. It is OPG's understanding that settlement amounts will always be calculated at the resource level as they are in today's market. Are there any situations where settlement amounts are calculated at the facility level? If so, examples or scenarios should be provided.	Settlement amounts will continue to be calculated at the resource level. The settlement design uses the term facility to reflect the terms used in the market rules for settlement. A facility by definition can include any equipment used to produce or consume energy, including a resource. There are no situations under which settlement amounts are calculated at a higher granularity than resource.
527	Market Settlement	OPG	The IESO should provide more information on how compliance aggregation will impact settlement amounts, such as but not limited to, real time make-whole payments and real time generator offer guarantee calculations.	Generation facilities which have been approved to use compliance aggregation will be settled based on the reapportionment of the measured generation quantity to the delivery point associated with the Compliance Aggregation Model based on dispatch instructions. This applies to all settlement amounts that requires measurement data as an input in the determination of the settlement amounts.

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528	Market Settlement	OPG	Under the current system, settlement data provided to market participants does not always include all the data necessary for Market Participants to adequately verify the amounts. For example, IESO statements do not include a line item when market clearing price (MCP) is equal to zero, which means the statement does not have complete records for energy injection and withdrawal quantities. For better transparency in the future market, OPG recommends future settlement statements include a detailed breakdown of calculations including all the necessary data for market participants to verify statement correctness. This should include line items when locational marginal prices are equal to zero.	The IESO will bring forward this comment for review during the implementation phase
529	Market Settlement	OPG	As per the design, settlement-ready Dispatch Data including Prices and Schedules have three categories: (1) As-offered, (2) Mitigated and (3) Enhanced Mitigated. To allow for proper reconciliation of settlement amounts, it is important for Market Participants to have all three categories of data and the logic for when each type of data is to be used to calculate the settlement amount. OPG recommends the IESO update the variable definitions, in section 3.5, to include an indicator to categorize dispatch data variables (like price, schedule, and offer/bid) and provide all three categories of data to market participants.	The IESO will provide all dispatch data used in the calculation of settlement amounts to market participants to allow for reconciliation of the settlement amounts. Details of the settlement data files will be provided during implementation phase.

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530	Market Settlement	OPG	Settlement Amount vs. Charge Types The IESO should continue the current market solution to apply multiple charge types for those settlement amounts that have multiple components. Such breakdown details will allow Market Participants to perform financial reconciliation and reporting. For example in section 3.7.1: DDDDDD_DDMMEEMM,hmm= DDMMMM[0,DDDDDD_CCCCDDEE1MM,hmm+DDDDDD_CCCCDDEE2MM,hmm] Where DDDDDD_CCCCDDEE1MM,hmm= −1 MM DDMEE{0,[CCEE(DDDDDD_LLDDEEhmm,DDDDDD_QQQQQQMM,hmm,DDDDDD_BBEEMM,hmm)−CCEE(DDDDDD_LLDDEEhmm,DDDDDD_EECCEEMM,hmm,DDDDDD_BBEEMM,hmm)] } And DDDDDD_CCCCDDEE2MM,hmm= −1 MMΣDDMEE{0,[CCEE(DDDDDD_EEPPCCPPEE,hmm,DDDDDD_QQQQCCPPEE,MM,hmm,DDDDDD_BBCCPPEE,MM,hmm)PP−CCEE(DDDDDD_EEPPCCPPEE,hmm,DDDDDD_EECCEEEE,MM,hmm,DDDDDD_BBCCPPEE,MM,hmm)]} DAM COMP1 and DAM COMP2 contain variables for energy, the three classes of operating reserve, outputs from the operating profit function, and the economic operating point. For proper reconciliation, all the variables should be provided to market participants and the components should have separate charge types. Some of the other calculations where this comment applies are: · RT_MWP which contains variables for lost cost and lost opportunity components for energy and operating reserve. These variables should be provided to the market participant · PPRR_DDMMEEMM,hmm=DDMMMM(0,EELLCCMM,hmm+EELLCCCCMM,hmm)+DDMMMM(0,CCLLCCMM,hmm+CCLLCCCCMM,hmm) · DAM_GOG & RT_GOG each have 5 components that should have separate charge types. The applicability of each variant should also be provided to market participants.	The IESO will provide all relevant information on each of the settlement amounts defined in the detail design to allow market participants to reconcile settlement amount on their respective settlement statements. With respect to operating reserves, separate settlement amounts will be provided for each class of operating reserve, as is today. More specific details will be provided on the settlement statements and the associated settlement data files during the implementation phase.

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531	Market Settlement	OPG	Per the design, the IESO has introduced new dispatch data, calculation engines, and mitigation processes; this consequently introduces a new and large set of settlement data and variables. § OPG requests publishing timelines and further details on the format of new private reports and settlement data files for the new data and variables. Some examples of new data and variables requiring clarification are: mitigation test results produced by DA/PD/RT calculation engines Eligibility variables, results for settlement amounts like: DAM-MWP, RT-MWP, DAM-GOG, RT-GOG, GFC and etc. For example, settlement data files should contain eligibility validation results in the form of an eligibility indicator (Y/N) to allow settlement amount reconciliation. § Variant: defined for DAM_GOG and RT_GOG. § Persistence Multiplier: used for settlement amounts like: RLSC and EXP_PWSC § Ramp-up and Ramp-down indication information in DAM and RT produced NQS unit schedules OPG also suggests the IESO include complete transaction lines in a statement or statement data file with eligibility indicator for settlement amounts like: DAM-MWP, RT-MWP, DAM-GOG, RT-GOG, GFC and etc.	Settlement statements and associated settlement data files will continue to be published according to the preliminary and final settlement timelines defined in IESO Settlement Schedule and Payments Calendars (SSPCs). Details of the settlement statements and settlement data files will be provided during the implementation phase.
532	Market Settlement	OPG	[...] OPG requests the IESO provide reports that will allow Market Participants to understand and reconcile the components of DRSU and how it applies to our resources. For example: public reports identifying the new or incremental schedules that are caused by the reliability scheduling pass and their associated DAM_MWP and DAM_GOG (aggregated to avoid confidentiality provisions), and private reports that identify resources that are specifically responsible for the increased uplift.	The IESO will bring forward this request for consideration during the implementation phase.
533	Market Settlement	OPG	[...] The concept of a transitional period is of concern to OPG because this could add complexity to its development of tools for managing settlements in the future market. OPG and other market participants require specific details on how this transitional period would work so it can be factored into the development of new settlement tools. [...] OPG believes the IESO should arrange a complete one-time switch rather than multi-phase implementation as all of these charge types are key changes between current and new market (e.g. Energy/OR, eliminating CMSC, DA-PCG, RT-GCG as well related uplifts). This would avoid the need for Market Participants to implement additional settlement calculation tools for managing settlements during a transition phase.	The IESO will provide more information on the transition between existing and new settlement amounts to stakeholders during the implementation phase.
534	Market Settlement	OPG	OPG notes we may have additional comments on Transmission Rights Settlements Amounts as the separate Transmission Rights Auction Review Stakeholder Engagement Process evolves. OPG would like more details and clarity on how the IESO plans on integrating the Transmission Rights Auction Review process with MRP. The improvements/changes to the Transmission Rights Auction should be implemented in tandem with MRP.	The proposed changes to the TR Market that result from discussions with stakeholders through this engagement will not be explicitly included in the MRP detailed design. However, MRP detailed design changes will need to be coordinated and considered in the discussion of changes to the TR Market through this engagement.

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535	Market Settlement	OPG	The business requirements of settlement-ready data processing (section 3.5.1) does not address timelines for publishing the data. The IESO should publish the settlement-ready data with adequate time for market participants to check for completeness and address any inconsistencies with the IESO to avoid the administrative burden of the Notice of Disagreement (NoD) process.	The IESO will continue to provide settlement statement and their associated settlement data files to market participants as per Settlement Schedule and Payments Calendar (SSPC), which is 10 business days after the trade date for preliminary settlement statement and 20 business days after the trade date for final settlement statements.
536	Market Settlement	OPG	In "Table 3-8: Facility Registration Data Used for Settlement", the design identifies the elapsed time to dispatch for use in settlements. After further review of the design, it appears the elapsed time to dispatch only impacts the eligibility for Generator Offer Guarantees. An explanation of the terms and their application when introduced in the design documents would be beneficial.	"Elapse time to dispatch " is one of the specific characteristics that is defined for a resource to be eligible for Generator Offer Guarantee. Additional information can be found in Section 4.3 "Eligibility for Cost Guarantee" in the Enhanced Real-Time Unit Commitment (ERUC) High-Level Design. A description has been provided in the Market Settlement detail design document and is a term that currently exists in Chapter 11 Definitions of the Market Rules.
537	Market Settlement	OPG	Table 3-9: Forbidden regions states: "DAM schedules which are at or within the boundary of a forbidden region will be adjusted prior to calculating the DAM make-whole payments." OPG believes DAM schedules within a forbidden region should not occur and requests the IESO provide clarification on the circumstances a resource would receive a DAM schedule within their forbidden region.	Forbidden region is a new daily dispatch data parameter that will use be by the DAM calculation engine to ensure that a hydroelectric generation facility is scheduled outside its submitted forbidden region. For information on the determination of hydroelectric generation facility schedules, please refer to Section 3.5.4.2 of the Grid and Market Operation Detailed Design document. The IESO will make the correction to Table 3-9 in V2 of the detailed design document.
538	Market Settlement	OPG	In "Table 3-9: Non-Financial Hourly and Daily Dispatch Data Used for Settlement" the following design parameters require clarification on units of measure: · Hourly Must Run · Minimum Hourly Output · Ramp Up Energy to MLP · Linked Resources, Time Lag, MWh These parameters are listed as MWh while MLP is listed as MW. The IESO should clarify the units of measure for each of these parameters.	The units of measure for the new dispatch data parameters for hydroelectric generation facility are correctly defined as MWh. MLP is defined as MW, as is today. These units of measure are consistent with the definitions in Section 3.4.2 "Generation Facility Dispatch Data to Supply Energy" of the OBDI detailed design document.
539	Market Settlement	OPG	[...] What intermediate modifications is the DAM calculation engine performing on DAM bid or offer data? Will this intermediate modification be transparent to impacted market participants?	The DAM calculation engine may modify DAM bids and offers as a result of mitigation and will be provided to the settlement process. Intermediate modifications made to DAM bids and offers as a result of mitigation will be provided to the impacted market participants.
540	Market Settlement	OPG	OPG requests clarification on whether the IESO is applying administrative fees for virtual transactions. [...]	There will not be an administration fee for virtual transactions. In the DAM HLD, the IESO proposed a number of design options to mitigate the risk of DAM failures due to the volume of virtual transactions. During the detailed design phase, the IESO determined that minimum offer or bid restrictions and market participant volume limits were sufficient to mitigate this risk.

ID	Design Document	Stakeholder	Stakeholder Feedback	IESO Response
541	Market Settlement	OPG	The design includes the following mitigation test results for the Day Ahead, Pre-dispatch, and Real-time calculation engines: pass or fail of conduct and impact tests, mitigated dispatch data, and resource constrained area mitigated test condition in Tables 3-12, 3-21, and 3-29 respectively. OPG recommends the IESO publish private reports that provide all records of market mitigation test results and subsequent enhanced mitigated data for all resources regardless of whether they pass or fail the conduct and impact tests. This would provide transparency in the market mitigation process for market participants. The design currently requires market participants to infer enhanced mitigated data for hours that did not fail testing, which impacts settlement amounts for, but not limited to, DA_GOG and RT_GOG.	The IESO will provide transparency in the market power mitigation process by providing confidential reports that provide relevant information to market participants who fail the conduct and impact tests and are mitigated as a result.
542	Market Settlement	OPG	Table 3-14 contains DAM Unit Commitment Events for: · Latest DAM pass prior to the Reliability Scheduling Pass of DAM Quantity of Energy Scheduled for Injection at a Delivery Point, · Reliability Scheduling Pass of DAM Quantity of Energy Scheduled for Injection at a Delivery Point, · Latest DAM pass prior to the Reliability Scheduling Pass of DAM Quantity of Energy Scheduled for Injection at a Intertie Metering Point, · Reliability Scheduling Pass of DAM Quantity of Energy Scheduled for Injection at an Intertie Metering Point, Latest DAM pass prior to the Reliability Scheduling Pass of DAM Scheduled Quantity of Operating Reserve at a Delivery Point, · Reliability Scheduling Pass DAM Scheduled Quantity of Operating Reserve at a Delivery Point, · Latest DAM pass prior to the Reliability Scheduling Pass of DAM Scheduled Quantity of Operating Reserve at an Intertie Metering Point, · Reliability Scheduling Pass DAM Scheduled Quantity of Operating Reserve at an Intertie Metering Point, Import DAM Make-Whole Payment Prior to the Reliability Scheduling Pass, · Import DAM Make-Whole Payment from the Reliability Scheduling Pass, · and DAM Generator Offer Guarantee from the Reliability Scheduling Pass OPG recommends the IESO publish private detailed reports with hourly results for all three DAM passes to provide information necessary for settlement amount reconciliation.	The IESO will bring forward this comment for consideration during implementation phase.

ID	Design Document	Stakeholder	Stakeholder Feedback	IESO Response
543	Market Settlement	OPG	The design for Table 3-14 "DAM Unit Commitment Events" requires clarification on the difference between DAM Unit Commitment Events and DAM Financially Binding Schedules. From review of the table, it appears the design is referring to financially binding schedules for all types of facilities (e.g. hydroelectric, nuclear, NQS, etc…), however, the title of the table is inconsistent with this.	DAM Unit Commitment is the operational commitment produced by the DAM Calculation engine for NQS generation units for their minimum generation block as defined by their MLP and MGBRT. DAM financial binding schedule refers to the DAM schedule produced by the DAM calculation engine for all supply and load resources. Table 3-14 defines the DAM schedules for all resources. The IESO will modify the title of the table to correctly reflect the content.
544	Market Settlement	OPG	The design for Table 3-15 "Financial Dispatch Data for Physical Transactions Submitted to the DAM" for "DAM Energy Offer at a Delivery Point" is limited to generating facilities. OPG recommends the IESO consider extending this to energy storage facilities for both physical energy and OR transactions. IESO's Interim SDP (Storage Design Project) will allow for resources to register as Energy Storage Resources (ESRs). Pumped hydroelectric resources may opt to register as an energy storage facility in the soon to be implemented Market Rules and Manual updates. OPG recognizes the SDP is not part of the MRP scope, but believes it is worth considering sooner rather than later.	Thank you for the feedback. The MRP Energy and Energy Storage Design Project initiatives, while not integrated within MRP, will continue to coordinate any updates as needed to reflect the interrelationship between the projects.
545	Market Settlement	OPG	In Table 3-15: Financial Dispatch Data for Physical Transactions Submitted to the DAM, the design states: "DAM start-up offer associated with financial offers for the first settlement hour 'h' of the DAM commitment period at delivery point 'm' for market participant 'k' per-start". OPG recommends the IESO include the inferred state of the unit (e.g. hot, warm, or cold) used by the IESO in determining the start-up costs in settlement data files. OPG notes in the Grid and Market Operations design, the IESO infers the start-up costs instead of obtaining them directly from as-offered data.	The IESO will bring forward this consideration for review during the implementation phase.
546	Market Settlement	OPG	In Tables 3-15 and 3-24, the design has provisions for DAM Start-Up Offer for a Delivery Point Failure and states: "DAM start-up offer associated with financial offers, subject to mitigation, at delivery point 'm' for market participant 'k' committed by the DAM calculation engine for the DAM commitment that bridges with the PD commitment that has a failure 'f'." This design element demonstrates the need for private reports for DAM and PD commitments, as well as, any failure event. IESO should provide detailed examples on when this applies and how it is settled.	The Guarantee Cost component of the Generator Failure Charge (GFC) will use the offers, prices and advisory schedules at the time of the latest binding commitment to determine the failure charge. Start-up offers use in the calculation of the GFC will be provide to market participants. Section 3.7.11 "Generator Failure Charge - Guarantee Cost Component" of the Market Settlement design document provides more details on the use and settlement of failed events. More information on settlement statements and settlement data files for failed events will be provided to stakeholders during the implementation phase.

ID	Design Document	Stakeholder	Stakeholder Feedback	IESO Response
547	Market Settlement	OPG	The design for Settlement Input Values Derived from DAM Data states: "The DAM calculation engine will use both dispatch data submitted in the day-ahead market and associated registration data. However, the settlement process will not receive these data elements directly from the DAM calculation engine in their final form. The settlement process will derive settlement input values from a combination of bid or offer data and DAM calculation engine data. " OPG recommends the IESO publish the settlement input values derived from DAM calculation engine solutions. This comment also applies to settlement input values derived from Pre-dispatch and Real-time calculation engines. In later comments, OPG provides an example of economic operating point as one type of derived data that should be published.	The IESO intends to publish settlement derived input data in DAM, PD and RT timeframes relating to pseudo units for the reconciliation of settlement amounts. Economic Operating Point(EOP) for energy and operating reserves in DAM and RT timeframes will be provided to market participants. EOP in the PD timeframe is not required in the calculation of any settlement amounts, hence it will not be reported. More information on the reporting of settlement derived input data will be provided during the implementation phase.
548	Market Settlement	OPG	[...] OPG requests additional information about the economic operating point (EOP) concept as this will impact how make-whole payments are calculated. The IESO should hold stakeholder sessions to outline the methodology for deriving the EOP and subsequent impact on market participant's ability to reconcile settlement amounts.	Details of the methodology for deriving the Economic Operating Point (EOP) will be documented in the market manuals. Stakeholders will have an opportunity to review and provide feedback on market manuals as part of the implementation phase.
549	Market Settlement	OPG	The IESO should publish reports for DAM, PD, and RT Economic Operating Point for energy and for all three OR classes. The EOP is required for reconciliation of make whole payments.	Economic Operating Point(EOP) for energy and operating reserves in DAM and RT timeframes will be provided to market participants. EOP data in the PD timeframe is not required for any settlement amounts and will not be reported. More information on the reporting of EOP will be provided during the implementation phase.
550	Market Settlement	OPG	In Table 3-31, Commitment Information from the RT calculation engine includes Notice of Failure for PD Commitment. The IESO should provide more details on how market participants will be informed of a notice of failure for PD commitment. As previously mentioned, the design requires private reports published for DAM and PD commitments, as well as, any failure event. As failure events occur in RT, they will likely need different treatment then DA and PD commitments Some settlement amount calculations require various elements like: (1) Component (2) Variant (3) Eligibility Criteria and (4) Failure Event. OPG suggests the IESO use reason codes to identify failure events, similar to the methodology used in Section 3.5.7 to identify when import/export schedules are manually altered. These reason codes for failure events should be included in settlement statement data files to allow a market participant to reconcile settlement amounts, such as Generator Failure Charge (GFC) and Real Time Generator Offer Guarantee (RT GOG).	Market participants are required to submit a notified of failure to the IESO when a resource is unable to fulfill its PD commitment either partially or fully, as defined in Table 3-31: "Commitment Information from the RT calculation engine". Notice of failure is used in the Generator Failure Charge - Market Price Component calculation, where the $/MW is determined according to the time the notification of failure was received by the IESO. The actual failure event period that is subjected to failure charge assessment will be determined by the IESO according to the criteria listed in Table 3-65: Types of Failure and Periods Subject to Failure Charge Assessment. The IESO knows that details on the failure events are valuable for stakeholders to reconcile settlement amounts. More information on failure events data will be communicated to the market participants well prior to go-live.

ID	Design Document	Stakeholder	Stakeholder Feedback	IESO Response
551	Market Settlement	OPG	[...] The IESO should include settlement data with a field to indicate when a facility is eligible or ineligible for payments. This is required for market participants to reconcile the settlement amounts. Further explanations are required regarding the circumstances when the IESO would adjust the first settlement for a facility that is dispatched below its DAM financially binding schedule. This may require a scenario(s) to explain	The IESO will provide all relevant data required by the market participants to reconcile their settlement amounts. The settlement data files will be determined during the implementation phase. In instances where a facility with a DAM financial binding schedule is dispatched down to meet a system reliability need, the IESO will offset any negative impact of real-time balancing as a separate settlement amount (DAM balancing credit) to restore the margin associated with the facility day-ahead settlement reflected by the first settlement. However, the IESO will not adjust the calculated two-settlement (first and second settlement) amounts as it provides transparency on the DAM settlement and RTM Balancing settlement.
552	Market Settlement	OPG	For the first formula for HPTSA {1}, to what level of detail will this calculation be broken down on settlement statements? For transparency and the ability to fully reconcile and report on settlement amounts, all variables that are used to calculate these amounts should be published PBC}, {variant 1} and {variant 2}.	PBC, Variant 1 and Variant 2 of the HPTSA{1} formula will be reported as separate amounts on the market participant settlement statement. More information on details of the settlement statement for HPTSA{1} will be provided to stakeholders during the implementation phase.
553	Market Settlement	OPG	The formula for First Settlement HPTSA – Formula Variant 2 is shown as a positive value but given this is a load withdrawing energy from the system, should it be negative? The formula for the Second Settlement HTSA on page 90 is negative as we would expect for a load withdrawal.	The IESO will correct the First Settlement HPTSA - Formula Variant 2 such that it results in a negative value for price responsive loads.
554	Market Settlement	OPG	[...] It is OPG's understanding that settlement amounts should always be at the resource level i.e. EDP level, not at the facility level. Please provide an example of when a settlement amount would be at the facility level.	Settlement amounts will continue to be calculated at the resource level. The settlement design uses the term facility to reflect the terms used in the market rules for settlement. A facility by definition can include any equipment used to produce or consume energy, including a resource. There are no situations under which settlement amounts are calculated at a higher granularity than resource.
555	Market Settlement	OPG	A new public report for Load Forecast Deviation Charge (LFDC) should be published at the earliest available time similar to other Market Price Reports. LFDC is required to reconcile settlement amounts for nondispatchable loads.	Load Forecast Deviation Charge (LFDC) will be provided to market participants on their settlement statements for the reconciliation of settlement amounts for non-dispatchable loads. The IESO will bring forward this comment for consideration during the implementation phase.
556	Market Settlement	OPG	The settlement statement for DAM_MWP should include a detailed breakdown of each variable used in the calculations of Component 1 and Component 2. Component 2 should have detailed breakdowns for each type of OR (i.e. 10S, 10N, and 30R).	The IESO will provided all relevant information to allow for settlement reconciliation of the DAM MWP. Settlement amounts for each operating reserve class will be provided as separate settlement amount on the settlement statement, as is today. More information on settlement statement for DAM MWP will be provided to stakeholders during the implementation phase.
557	Market Settlement	OPG	Detailed breakdowns of each variable used for the calculation of each Component in the make whole payment on settlement statements is required for improved transparency. This would allow market participants to verify and confirm amounts.	The IESO will provide the relevant information to allow market participants to verify and reconcile all settlement amounts provided on their settlement statements. More information on settlement statements for each settlement amounts will be provided to stakeholders during the implementation phase.

ID	Design Document	Stakeholder	Stakeholder Feedback	IESO Response
558	Market Settlement	OPG	On page 100, the DAM MWP formula for cascade hydroelectric is: "Σ[DDDDDD_CCCCDDEE1MM,h+RRLLmmmm+DDDDDD_CCCCDDEE2MM,h+RRLLmmmm]DD>0" It does not include how make-whole payments are calculated across multiple trade dates. Please provide the methodology to settle any make-whole payments resulting from hydroelectric time lag across two trade dates.	DAM calculation engine will evaluate dispatch data for linked resources independent of linked resource dispatch data submissions and schedules from the previous dispatch day, therefore the DAM MWP does not require treatment across multiple trade dates. More information on the scheduling of linked resources can be found in Section 3.5.4.2 under "Scheduling Linked Resources at the Boundaries of the DAM" of the Grid and Market Operation Detailed Design document.
559	Market Settlement	OPG	Please provide further information on the process (es) the IESO will follow to determine if hydroelectric resources are eligible for make whole payments related to Min DEL, Minimum Hourly Output, and Hourly Must Run. OPG recommends the IESO include eligibility indicators on settlement data files to allow for reconciliation of settlement amounts.	As per the detailed design, generation facilities with a MinDEL are not eligible for make-whole payment when the constraints are binding. This is consistent with the current eligibility rules for CMSC related to SEAL. The rules for determining eligibility of DAM MWP for hydroelectric generation are described in Section 3.7. under "Eligibility for a Generation facility with Minimum Daily Energy Limit". The IESO will provide all data required to allow for reconciliation of settlement amounts during implementation phase.
560	Market Settlement	OPG	[...] OPG notes that hydro facilities should not receive a schedule within a forbidden region. The IESO should provide an example of a situation where a schedule could be received within a forbidden region. Refer to Comment #14 for additional information.	Forbidden region is a new daily dispatch data parameter that will used by the DAM calculation engine to ensure that a hydroelectric generation facility is scheduled outside its submitted forbidden region. For information on the determination of hydroelectric generation facility schedules, please refer to Section 3.5.4.2 of the Grid and Market Operation Detailed Design document.
561	Market Settlement	OPG	In regards to the following statement on Page 100: "DAM_MWP for these generation facilities will be assessed on a per-start basis when the number of starts within a trading day is equal to the maximum number of starts per day parameter provided by the market participant as part of the daily dispatch data." OPG is concerned that this assessment would be very complicated if applied to hydro resources in addition to NQS units. If this applies to hydroelectric, the IESO should provide details on the process involved.	The maximum number of starts per day is one of the parameters that will be used by DAM calculation engine to optimize the NQS schedules and commitments, however it will not be used in the calculation of DAM MWP for NQS. The IESO will assess DAM MWP for a hydroelectric generation facility on a per-start basis only if MinDEL is not binding and the number of start events in the trade day is equal to maximum number of starts as per the submitted dispatch data. For each start, the IESO will offset all revenue earned against costs incurred over the period of the start. Hours with a binding constraints will be excluded from the DAM MWP assessment as they are not eligible for make-whole payment. For all hours that are not part of a start, these will be assessed separately for DAM MWP. The rules for determining eligibility of DAM MWP for hydroelectric generation are described in Section 3.7. under "Eligibility for a Generation facility with Minimum Daily Energy Limit".
562	Market Settlement	OPG	For Component 2 of the DAM_MWP calculation, the IESO should provide more details on how this is split between the 3 OR classes. This comment also applies to all OR related settlement charges in the design, i.e. they should be broken down by OR class.	The IESO will report operating reserve broken down by each operating reserve class for all settlement amounts, as is today. This includes first and settlement amounts, DAM MWP, RT MWP, RT GOG and DAM GOG.

ID	Design Document	Stakeholder	Stakeholder Feedback	IESO Response
563	Market Settlement	OPG	OPG requests the IESO provide DAM_MWP calculations examples for at least the two scenarios below: · A dispatchable NQS unit offered energy and 30-minute OR, and entitle both DAM_MWP energy and OR compensations · Two cascade hydro resources with a one hour time lag, how is the DAM_MWP calculated for both units, and how to calculate for the period cross trading date in the mid-night Please also explain how the EOPs are calculated and used in MWP calculation.	EOPs are used in make-whole payments calculations to determine lost cost in DAM and lost cost and lost opportunity costs in RT MWP for both energy and operating reserves. The details of how EOPs are used in the calculation of make-whole payment is described in Section 3.7.1 under "DAM_MWP Formulation" and Section 3.7.5 under "RT_MWP Formulation". Details of the methodology for deriving the Economic Operating Point (EOP) will be provided in the market manuals. Market manuals and market rules are part of the implementation phase and will be discussed with stakeholders at that time.
564	Market Settlement	OPG	In Section 3.7.2, the design states: "An NQS generation unit not associated with a pseudo-unit will be eligible for a DAM_GOG if it meets all of the following criteria: · the generation unit is not a quick-start unit; · the generation unit has a minimum loading point (MLP) greater than 0 MW; · the generation unit has a minimum generation block run-time (MGBRT) greater than one hour; and · the generation unit has an elapsed time to dispatch greater than one hour as recorded during the Facility Registration process." These eligibility criteria are inconsistent with Table 3-5 of the Facility Registration Detailed Design, where the Generation Resource Registration Parameter for Generation Offer Guarantee Status indicate NQS (Nuclear) units are eligible for GOG, however, they cannot register for MLP or MGBRT. The IESO should address this discrepancy.	The Generator Offer Guarantee Status parameter applies to all NQS resources and is used to identify if the NQS is eligible for GOG payments. However, nuclear resources are not eligible for GOG as it does not meet the criteria defined in Section 3.6.1: Generator Offer Guarantee Status of the Facility Registration detail design document in order to qualify for GOG status.
566	Market Settlement	OPG	In section 3.7.2 the design states: "An NQS generation unit not associated with a pseudo-unit will be eligible to recover the implied costs of any start-up offer if:"... "the generation unit attains the MLP within the first 90 minutes of its DAM schedule or earlier as a result of being advanced by PD;" OPG requests the IESO confirm that the requirement is to attain MLP within 90 minutes of the DAM MLP schedule (i.e. not to reach MLP within 90 minutes of the DAM schedule). Please provide an example with 2 hours of ramp up energy to MLP to demonstrate the eligibility for implied costs of start-up offers.	The IESO can confirm that the requirement is to attain the minimum loading point (MLP) within 90 minutes of the DAM schedule at MLP. Table 3-57 describes the eligibility to recover the implied cost of start-up offers on the basis of when the resource achieves the MLP in order to meet its DAM financially binding schedule. If a generation unit has 2 hours of ramp up energy, and has met all the eligibility criteria defined in Section 3.7.2 under "Eligibility for Recovery of Implied cost of Start-up Offers", the generation unit would be able to recovery it's implied cost for start-up as follows: 1) If it reaches MLP within 2 ½ hours, it would be able to recovery the full start-up offer. 2)After 2 ½ hours, the start-up offer would be reduced by 1/12 for every 5-minute interval that it was late getting to MLP. 3)If it reaches MLP after 3 ½ hours, the generation unit would not able to recovery any start-up offer
567	Market Settlement	OPG	[...] Additional information is required on how escalating start-up costs will be considered for market power mitigation reference levels.	The formula for how the IESO will calculate the reference level for escalating costs is described in Section 3.13.1 "Late Day Start Offer Treatment" of the Market Power Mitigation Detailed Design document.

ID	Design Document	Stakeholder	Stakeholder Feedback	IESO Response
569	Market Settlement	OPG	In regards to the first sentence of the second paragraph under RT_MWP Formulation (Page 122):"If a facility deviates in the opposite direction of both its lost cost economic operating point and real-time schedule, the lost cost component will be set to zero." Followed on Page 123 by: "During any metering interval 't' within settlement hour 'h' in which the mathematical sign PPRR_QQQQQMM,hmm,tt - PPRR_LLCC_EECCEEMM,hmm,tt is not equal to the mathematical sign DDQQEEQQMM,hmm,tt - PPRR_LLCC_EECCEEMM,hmm,tt, the component EELLCCMM,hmm shall be set to zero." And "'ELCk,hm' is the total lost cost component of the RT_MWP for market participant 'k' at delivery point 'm' during settlement hour 'h' for energy attributed to the facility as a result of being dispatched up relative to its real-time lost cost economic operating point. " The equation as currently written will cause the component ELC to be set to zero almost all of the time. This may not be the appropriate settlement, as there are a number of reasons why RT schedules are different than the allocated quantity of energy injected and these should not set the entire lost cost component to zero, such as: · Differences between operational and revenue meters· Use of compliance aggregation · When a dispatch is sent by the IESO, the generator is to achieve it by the end of the interval. · Ramp rate considerations and existing slow-mover logic for following dispatch. The ELC is intended to compensate for the lost cost when a facility is dispatched up relative to its real-time lost economic operating point. The IESO should revise the equation to allow facilities to recover their lost costs.	The ELC is intended to allow market participant to recover any lost cost incurred above its economic operating point (EOP) in order to meet its dispatch instruction. When a resource deviated from it's dispatch instruction such that it is operating below it's economic operating point based on the revenue meter at the resource, it is not incurring any lost cost and will not be compensation for ELC. The rule: "During any metering interval within settlement hour in which the mathematical sign RT_QSI - RT_LC_EOP is not equal to the mathematical sign AQEI - RT_LC_EOP, the component ELC shall be set to zero." achieves the intended outcome of not providing a lost cost compensation in these instances. With regards to the scenarios identified, these should not result in the resource deviating from dispatch instruction such that it is operating below its EOP.
570	Market Settlement	OPG	It is unclear whether it is a generator's ELOC to be negative. If it can be negative, the IESO should provide an example of when this occurs. Similarly for OR, it is unclear whether the OLOC for a generator or export be negative. If it can be negative, please provide an example of when this occurs.	The total lost opportunity cost of the RT MWP for energy (ELOC) and the total lost opportunity cost of the RT MWP for operating reserves (OLOC), can be negative. The methodology for determining Economic Operating Point (EOP) will be addressed in the implementation phase.

ID	Design Document	Stakeholder	Stakeholder Feedback	IESO Response
573	Market Settlement	OPG	The description of the ELOC calculation is not consistent within the design. Two examples are provided below: In page 122, the 3rd paragraph under RT_MWP Formulation: “For the purpose of calculating the lost opportunity cost, market participant offers and bids will be adjusted. The energy offers associated with a generation facility and operating reserve offers will be adjusted to the greater of the offer price and the associated real-time market price.” However, in page 123, 2nd paragraph, “In order to calculate the component *EELLCCCCMM*, *hmm* for a generation facility, the IESO will adjust any energy offer price that is greater than the real-time energy price to the lesser of the energy offer price and the realtime energy price.” Since the intent of ELOC is to compensate market participants for lost opportunity cost, the IESO should assess whether the greater of the offer price and the associate real-time price accomplishes this objective.	The detail design document will be updated to correctly reflect that in order to calculate the component ELOC, energy offers associated with a generation facility and operating reserve offers will be adjusted to the lesser of the offer price and the associated real-time market price.
575	Market Settlement	OPG	For RT-GOG eligibility, OPG recommends that units receive similar treatment for proration if they trip during their MGBRT as they get under the existing DACP.	In the current market, the RT-GCG program allows a generation unit to recover its costs only if it comes online and completes its full MGBRT. In the future market, RT-GCG will be replaced by RT-GOG. Under RT-GOG, if a generation unit does not complete its MGBRT, it will not be eligible for start-up cost compensation. However, the generation unit will be eligible for SNL and energy cost recovery for hours where it is at or above MLP, whether or not it completes its MGBRT. SNL will be reduced by 1/12th for each 5-minute interval where the generation unit did not produce energy for the full hour, similar to DACP.
576	Market Settlement	OPG	Please clarify if Generator Failure Charges are applied when a NQS unit reaches MLP late. The design should ensure the interaction between Generator Offer Guarantee and Generator Failure Charge does not create a doubling effect on the penalty for reaching MLP late.	The Generator Failure Charge will apply if a NQS fails to reach MLP before the first interval where a generation unit has an operational constraint for PD commitment. The Generator Offer Guarantee and Failure change interaction is not intended create a double penalty effect to the generation unit. The charge types are designed to work together to ensure that NQS generation units are compensated fairly and reduce the risk of system reliability events due to failed commitments. The Generator Offer Guarantee is intended to compensate the generation unit according to the real-time performance for the cost incurred during the period where the generation unit fulfills its unit commitment. The Generator Failure Charge is intended to recover the additional cost incurred by the market during the period where the generation unit failed to meet its commitment.

ID	Design Document	Stakeholder	Stakeholder Feedback	IESO Response
577	Market Settlement	OPG	The first sentence on this section on Page 136 states: "When a generation unit reaches MLP late, the IESO may extend the unit's operational constraint beyond its initial commitment to ensure the generation unit completes its MGBRT." OPG is concerned about the use of the word "may" in this statement. In order to fulfill SEAL obligations, the IESO would have to extend the commitment to ensure MGBRT is met. The word "may" should be changed to "will".	The IESO will make your proposed change. The revised sentence will be: "When a generation unit reaches MLP late, the IESO will extend the unit's operational constraint beyond its initial commitment to ensure the generation unit completes its MGBRT."
579	Market Settlement	OPG	In Section 3.7.9, Paragraph #1 the design states: "The IESO will provide the RT_GOG payment to compensate market participants for any loss they incur relative to costs implied by their offers for the period in which their resource is committed by the pre-dispatch calculation engine." Based on the above statement, OPG thinks applying "Min(OP(RT_LMP, RT_QSI, BE) , OP(RT_LMP, AQEI, BE))" function (instead of "Max") in the RT_GOG_COMP1 calculation on page 139 is more appropriate as it is the worst case loss.	The IESO believes using the Max(OP(RT_LMP, RT_QSI, BE), OP(RT_LMP, AQEI, BE) is the appropriate solution and better aligns with the intent of the GOG design. By using the maximum operating profit of the real-time dispatch schedule and real-time injection, the formula incentivizes the generation unit to follow the IESO dispatch as closely as possible. According to the formula, the operating profit is used to offset the speed no load cost and start-up cost to determine the loss incurred by the generation unit. If the actual loss implied by the AQEI is smaller than the loss implied by the real-time dispatch schedule, then the generation unit will only be compensated for the loss it actually incurred. If the actual loss incurred is greater than the loss implied by the real-time dispatch schedule, the market participant will bear the additional loss beyond what was scheduled. Using the Min function to cover the worst case loss does NOT align with the incentive of the GOG design.
580	Market Settlement	OPG	Table 3-64 implies that generator failure charges apply to "applicable generation unit within Ontario". OPG suggests the IESO add the "NQS receiving a PD commitment" to this statement for clarity. It is OPG's understanding that failure charges will only apply to NQS generators.	Thank you for your feedback. The detail design specified that the calculation of the Generator Failure Charge will occur when a generation unit fails to deliver energy as committed by the PD calculation engine. Table 3-64 will be edited to "applicable NQS generation unit within Ontario receiving PD commitment" to align with the intent of the Generator Failure charge.
581	Market Settlement	OPG	There are at least two instances of inconsistent units of measure as defined in Tables and later used in formulas. All units of measure need to be reviewed to ensure consistency in their definition and use. Two such instances are provided below: In Table 3-24, the MLP_INJ variable defines measurement in MW. However, in the formula at the bottom of Page 153, the MLP_INJ is shown to be the number of intervals. Table 3-24 requires a correction. Similarly, in Table 3-24, the PD_SU_MLP is defined as a price variable with measurement unit in $ amount , but in the formula at the bottom of Page 153, it appears to be a proration factor. Table 3-24 requires a correction.	Thank you for your feedback. The IESO will make the modification to Table 3-24 to reflect the following correction: The unit of measurement of MLP_INJ will be corrected to # of intervals. The unit of measurement for PD_SU_MLP will be removed as this is a proration factor.

ID	Design Document	Stakeholder	Stakeholder Feedback	IESO Response
582	Market Settlement	OPG	If a failure charge is incurred for a PD commitment that crosses multiple dispatch days, how is the charge allocated to each day? The formula at the top of Page 161 for GFG_MPCU should provide details on commitments that cross over to the next trade day.	Generator Failure Charge – Market Price Component (GFC_MPC) will be assessed on an hourly basis, and it will calculate a charge for every interval within that hour that is classified as a Failure Interval, as defined by Table 3-65: Types of Failure and Periods Subject to Failure Charge Assessment. Generator Failure Charge - Guarantee Cost Component (GFC_GCC) represents an approximation of the guarantee cost of the replacement generation unit, therefore a given failure will be calculated for the entire set of Failure Intervals associated with that failure (as defined in Table 3-65). The treatment for failure crossing over midnight will be similar to GOG, where a given failure event that crosses over midnight will be assessed as a single event that is associated with the dispatch day when the binding start-up instruction was issued.
583	Market Settlement	OPG	OPG would like the IESO to clarify how Congestion Rent and Loss Residuals Disbursements (CRLRD) will be calculated and published to market participants. In section 3.7.14, the formula for CRLR is defined as: "CRLR = [term1] + [term2] + [term3] + [term4] – [term5] [term1] congestion rent and marginal loss accrued in the DAM and the real-time market to settle all generators, dispatchable loads and price responsive loads + [term 2] congestion rent and marginal loss accrued in the DAM and the real-time market to settle virtual transactions + [term 3] congestion rent and marginal loss accrued to settle NDLs + [term 4] congestion rent and marginal loss to settle boundary entities - [term 5] congestion rent collected on interties when interties are either import-congested or exportcongested" For increased transparency, the IESO should publish all terms of the formula, as well as, the total.	The Congestion Rent and Loss Residual Disbursement (CRLRD) will be calculated monthly and provided to market participant on the settlement statements of the last trading date of each month. More information on the settlement statement for CRLRD will be provided during the implementation phase.
584	Market Settlement	OPG	The IESO should publish estimates of the monthly Congestion Rent and Loss Residual Disbursements (CRLRD) rate as first estimates, second estimates, and actual values similar to how the IESO currently publishes Class A/B Global Adjustment rate estimates and actual values.	Due to the monthly variation due to uncertain market and system conditions impacting congestion and losses, the IESO is unable to produce estimates.
585	Market Settlement	OPG	In future settlement statements with GSSR, the IESO should flag or indicate the hours where each resource is eligible for GSSR. This would improve transparency and make it easier for market participants to reconcile settlement statements.	The IESO will bring forward this comment for review during the implementation phase.
586	Market Settlement	OPG	The IESO should include a clear indicator of a generator's ramp-down period on its settlement (schedule) data. This would improve market transparency and make it easier for MPs to reconcile their settlement statements. The IESO also needs to clarify how the ramp-down period is settled if it crosses over to the next day (i.e. crosses midnight).	When the ramp down period crosses over midnight, the generator will continue to be compensated through the ramp down settlement amount if the revenue received for hours where the resource is scheduled below MLP does not cover the cost incurred during the same hours. The IESO will provide all relevant information to market participants for the reconciliation of settlement amounts. Details of the settlement statement and associated settlement data files will be provided during implementation phase.

ID	Design Document	Stakeholder	Stakeholder Feedback	IESO Response
587	Market Settlement	OPG	[…] The IESO should develop a transparent process and methodology that allows market participants to understand the after-the-fact settlement corrections and which transactions are directly impacted. This should include whether the corrections only apply to physical/virtual transactions or extend to facilities such as generators. There should also be a Notice of Disagreement (NoD) process that market participants can use to either dispute or request these corrections.	The IESO will provide transparency on the process and methodology for after-the-fact settlement corrections (i.e. dispatch scheduling errors) as part of the market manuals. More information on market manuals will be provided during the implementation phase. As is today, market participants will continue to be able to submit NODs for incorrect settlement amounts or settlement amounts that did not appear on their preliminary settlement statements.
588	Market Settlement	OPG	[...] Please provide details on why market schedules are omitted from administrative pricing events. How will operating reserve and intertie schedules be administered?	In the current market, when an administrative pricing event occurs in real-time, the unconstrained schedules are updated because we have an unconstrained run and the unconstrained schedules need to align with the administered unconstrained prices. Constrained schedules are only updated to reflect the actual dispatch instruction that was issued if it differs from the schedule recorded in the system, such as a verbal instruction for energy or operating reserve, and to align with the schedule that is agreed upon with neighbouring jurisdiction for intertie transactions. In a single-schedule market, there is only a single schedule that will be reflective of conditions in real-time and the market schedule will cease to exist. When prices are administered, energy and operating reserve schedules will not need to be updated, unless as today, they are updated to align with verbal instructions or the agreed upon schedules with neighbouring jurisdictions.
589	Market Settlement	OPG	During the early transition to the new market, the timeline for Notice of Disagreement (NoD) submissions should be extended, e.g. extend NoD submission window from 4 business days to 6 business days. This would provide MPs with more time to review IESO preliminary statements and reconcile the more complex settlement data introduced by the new Market solutions. OPG also notes that during the early phases of the new market it would be beneficial if the IESO could respond within a reasonable period of time (e.g. 6 business days, in reflection with the timeframe that is given to MPs) with NoD decisions or feedback on submissions as this would allow MPs to determine and resolve potential system implementation issues as well improve processes for future settlements.	The IESO has initiated a review and potential for changes to the NOD process, as discussed at the engagement meeting on September 29th regarding "Proposed Settlement Statements Recalculations Process". All NOD-related requests will be addressed through this initiative, and feedback on the proposal is due October 20, 2020. The IESO will also work closely with participants during the Implementation phase to provide documentation and background to the Charge Types and Equations that will used in the renewed market.
595	Market Settlement	OPG	The IESO should publish the market manual documents identified below as early as possible: § IESO Charge Types and Equations § Format Specification for Settlement Statement Files and Data Files This will help Market Participants understand the calculation rules for new settlement amounts, and to determine if all required information will be available for MPs to perform shadow settlement and settlement statement reconciliation.	The IESO Charge Type and Equations and Format Specification for Settlement Statement File and Data Files are part of the implementation phase, and will be provided during that discussion.

ID	Design Document	Stakeholder	Stakeholder Feedback	IESO Response
596	Market Settlement	OPG	In Table 5-1 (page 245), the IESO should include changes required to update Section 1.6.1 in the Market Manual 5: Settlements, Part 5.5 – Physical Markets Settlement Statement, to clarify which new uplift settlement amounts and charge types will be included in Generation Station Service Rebate.	The Settlement market manuals and IESO Charge Type and Equation document will be updated to include new uplift settlement amounts that are applicable to Generation Station Service Rebate.
597	Market Settlement	OPG	As per the design in sections 3.7 and 3.8, the Replacement Energy Offer Program and Administrative Pricing Event will still occur after market renewal, as such, the IESO should revisit whether their subsequent market manual sections should be updated rather than deleted. As CMSC is no longer valid, the IESO should assess how make-whole payments apply for both replacement energy and administrative price events. Table 5-1 (page 245) needs to be revised to "Update section" instead of "Delete section".	Although market participants will continue to be able to use the Replacement Energy Offers Program (REOP), the Pre-dispatch scheduling process will economically schedule resources based on the revised dispatch data submitted during the mandatory window and will be automatically settled as per the design in Section 3.7.5, 3.7.9 and 3.7.11 of the detail design document. The Replacement Energy Offers Program (REOP) is described in the Section 3.8.2 of the Grid and Market Operation Detailed Design document. With respect to Administrative Pricing Events, the settlement process will be informed of administrative pricing events and the make-whole payment calculations will use the administered prices in the calculation of the settlement amounts. However, if a Dispatch Scheduling error is declared, after-the-fact settlement corrections may be required to settlement amounts. Details of the settlement process to address Dispatch Scheduling errors will be provided in the market manuals during implementation phase. For more information on Market Remediation, refer to section 3.9 of the Grid and Market Operation Detailed Design document.
598	Market Settlement	OPG	As stated in Page 247, the IESO proposes to add new sections for a list of new Settlement Amounts in Market Manual 5: Settlements, Part 5.5 – Physical Markets Settlement Statement. OPG suggests the IESO add specific examples to illustrate: (1) how eligibility is determined and (2) how these new settlement amounts and charge types, e.g. MWP, GOG, Failure Charge and etc. are calculated (similar to current section 1.6.10 with both descriptions and demonstration examples for real-time import failure charges and export failure charges). This would allow Market Participants to understand the IESO design and design settlement systems that are able to reconcile and verify settlement amounts.	Market manuals and market rules are part of the implementation phase, and will be reviewed with stakeholders over the coming months.
599	Market Settlement	OPG	In pages 248/249, in addition to IESO listed items, the IESO should consider adding specification for below components in IMP_SPEC_0005 Format Specification for Settlement Statement Files and Data Files: § Market Power Mitigation results, e.g. indicators for dispatch data (price and schedule) was produced upon ex-ante mitigation functions. § Eligibility and Variant indicators information for new Settlement Amounts are calculated upon (1) eligible/ineligible criteria, (2) applicable Variant scenario and (3) applicable persistence multipliers	The IESO will bring forward this comment for review during the implementation phase.
600	Market Settlement	OPG	All Appendix sections in Market Manual 5: Settlements, Part 5.5 – Physical Markets Settlement Statement need to be updated to reflect the Market Renewal solutions	The Settlements market manuals will be updated to align with the designs described in the Market Settlement detailed design document. These will be available for stakeholder review as part of the implementation phase.

ID	Design Document	Stakeholder	Stakeholder Feedback	IESO Response
601	Market Settlement	OPG	The IESO should add Process P1 specification for: § The price and schedule information used in Process P1 could have ex-ante mitigation results produced by DAM and RT calculation engines [in page 254 & 255] § LFDC (Load Forecast Deviation Charge) is part of Non-dispatchable Load Settlement Amount	The design document will be updated with the proposed changes.
602	Market Settlement	OPG	Please clarify: DAM Commitments: (1) Last DAM Calculation Engine pass and (2) Reliability Scheduling Pass. vs. DAM_SQI i.e. DAM Schedule [in page 264] § how the three set Dispatch Data are used in Settlement Amount calculations: (1) As-offer, (2) mitigated and (3) enhanced mitigated [in page 271]	DAM Commitments are operational commitment produced by the DAM Calculation engine for NQS generation units for their minimum generation block as defined by their MLP and MGBRT. "Hourly schedules from the Last DAM Calculation Engine pass prior to the reliability scheduling pass" and "Hourly schedules from the reliability scheduling pass" are DAM commitment results from DAM Calculation Engine Pass 1 and Pass 2 respectively. DAM Schedule data is the financially binding schedule determined by the final pass (Pass 3) of the DAM calculation engine. The as-offered, mitigated and enhanced mitigated data will be used by the settlement process for settlement mitigation of make-whole payments as described in Section 3.8 of the Market Power Mitigation detailed design document and applied to make-whole payments and other guarantee payments as specified in Section 3.13 of this design document.
603	Market Settlement	OPG	The IESO should add P7 and P8 data as inputs to Process P5, this would show how P5 would take into account P7 and P8 produced results.	The design document will be updated with the proposed changes.
604	Market Settlement	OPG	[...] The IESO should allow market participants to submit a NoD for expected settlement amounts which were not paid by IESO and did not appear on preliminary statement.	Market participants are allowed to submit NODs for settlement amounts that did not appear on the preliminary statement, as is today. The IESO will make the correction to the design document in V2.

Offers, Bids, and Data Inputs

ID	Design Document	Stakeholder	Stakeholder Feedback	IESO Response
442	Offers, Bids, and Data Inputs	Capital Power	Could the IESO please provide more information on the proposed pricing locations, specifically the following details: When will the new definitions for pricing locations be released? Is it possible for different resources at the same site to have different pricing? If so, what would be the impact on dispatches and competition?	Pricing locations will be defined for all resources that are settled for energy and/or operating reserve in the future market. The locations currently defined for shadow prices will be the same locations used for LMPs. It is possible for different resources at the same location to have different prices. For example, when outage conditions at the station connect resources to different parts of the system. Different prices will reflect different dispatch needs for the system and support a competitive market.
444	Offers, Bids, and Data Inputs	Capital Power	Within the draft design, thermal generators not classified as Non-Quick Start ("NQS") will only be permitted to submit one-part offers. One-part offers do not match the actual cost structure of these assets, as start-up and speed no-load costs are incurred. Requiring these assets to submit one-part offers will require speculation as to how long they may run and, in turn, offer prices to recover all costs (i.e., start-up, speed no-load, energy) for the projected time of operation. This differential treatment could foreseeably lead to inefficiencies because these generators, like NQS generators, will not always be able to project for how long they will run when they submit their offers and yet they will not be able to participate in programs that help mitigate the risk of cost-non-recovery . They will also be subjected to Market Power Mitigation ("MPM") and Make-Whole Payment ("MWP") clawback if they run longer than projected resulting in resources running at a loss and leading to further inefficiencies.	As decided during High-Level Design (HLD) and outlined in the Enhanced Real-Time Unit Commitment HLD document, submission of three-part offers for quick start resources is not in scope for Market Renewal.
445	Offers, Bids, and Data Inputs	Capital Power	Thermal Generators not classified as NQS do not appear to be eligible for Generator Offer Guarantees. This will force these units to assume greater risk than other asset classes. (see 3.7.9 Settlements RT_GOG)	As decided during High-Level Design (HLD) and outlined in Section 4.3 of the Enhanced Real-Time Unit Commitment HLD document, a resource must have an elapsed time to dispatch greater than one hour to be eligible for a cost guarantee.

ID	Design Document	Stakeholder	Stakeholder Feedback	IESO Response
448	Offers, Bids, and Data Inputs	Capital Power	3.4.2 Start Up Offers • Limiting start profiles to Hot, Warm and Cold values may limit system flexibility. Combined Cycle Generators can restart very quickly by maintaining Full Speed No Load (FSNL). If a generator is utilizing Single Cycle mode of operations, a start may also be executed much quicker than in Combined Cycle mode of operation. It is not clear if the design will enable this level of system flexibility.	The design provides flexibility for generators to vary their hot state data submissions to reflect 'very hot' conditions. The calculation engines are not capable of evaluating more than 3 thermal states. Providing market participants with the ability to vary their dispatch data for each of the three states is an alternate way to provide similar flexibility. '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. These validation rules are provided in the Offers, Bids and Data Inputs design document (Lead time and minimum generation block down time subsections within Section 3.4.2) For example, hot lead time and hot down time values of zero can be used to reflect FSNL conditions. This tells the DAM and PD calculation engines 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.
450	Offers, Bids, and Data Inputs	Capital Power	3.4.2 Start Up Offers • It may be impossible to make the proper start up profile election in DAM if a participant does not yet know their operating schedule in the current day. Capital Power requests that the IESO review this element to ensure feasibility and implementability."	In today's market, market participants that do not yet have an operating schedule in the current day submit dispatch data into the DACP that best reflect their anticipated start up profiles based on their scheduling expectations for the remainder of the current day. The market participant is in effect 'electing' the most feasible and implementable start-up profile for the next day. The same situation can occur in the future DAM, and market participants will have the same flexibility to submit start up profile values that best reflect their expectations. The use of 'election' in the design document is meant to describe that a market participant has the ability to submit either a hot, warm or cold start-up profile into the DAM and assign a value for the chosen state that best reflects a feasible and implementable start-up profile for their resource.
457	Offers, Bids, and Data Inputs	Capital Power	The IESO's example on page 33 suggests there is limited flexibility for resources to update their start profile during the day. According to the example, if a Generator comes off-line during the day it will always be in a hot state for the remainder of the day. o Will the tool be able to recognize when a generator is off-line for multiple days?	The design provides market participants with the flexibility to update their start profile parameters to reflect intra-day changes in thermal status. As per response to feedback about recognizing additional states such as FSNL, market participants can vary their hot, warm and cold dispatch data values to reflect 'hotter' and 'colder' conditions. The PD calculation engine will be capable of recognizing that a resource has been offline for at least one day because it uses the previous day's DAM and PD schedules to see whether a resource was online or offline during that day.
462	Offers, Bids, and Data Inputs	Capital Power	It is not clear what offer price restrictions will apply to operating reserve. Further details are required.	The only price restrictions for operating reserve are that the price must be no greater than $2000 (the maximum operating reserve price, +MORP) and no less than $0 (the minimum operating reserve price, -MORP). These are the same boundaries used in today's market. The Offer to Provide Operating Reserve section will be updated to provide this clarification.

ID	Design Document	Stakeholder	Stakeholder Feedback	IESO Response
465	Offers, Bids, and Data Inputs	Capital Power	More detail is required to assess the impact of this section (3.5.1). The proposed requirement will affect the operation of the MPM framework, and this impact will be important to understand.o What criteria does the IESO apply to set min and max requirements?o Where will it be documented?o Will stakeholders have input?	The IESO will set minimum operating reserve requirements for areas of the system that could be undersupplied and maximum reserve requirements for areas of the system that could be oversupplied, because of anticipated transmission constraints that limit the amount of energy that can flow into and out of those areas. The IESO will consider documenting the criteria to establish min and max area reserve requirements during market manual development currently scheduled during Q2 and Q3 of 2021. Stakeholders will have an opportunity to provide feedback on the proposed content for market manuals.
466	Offers, Bids, and Data Inputs	Capital Power	More details are required to inform market participants on the 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 the IESO can relax constraint violation penalty curves so they will, therefore, not set LMPs.	All of the constraint violation penalty curves 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).
467	Offers, Bids, and Data Inputs	Capital Power	To properly assess this design element (Constrained Area Designations), historical information is necessary. Market participants will need to understand if they can expect to be within a constrained zone to understand the impact. Timing of when, if at all, the IESO expects to provide this data to stakeholders should also be communicated.	The IESO will use currently available data to provide an assessment of what areas of the grid would be classified as a narrow constrained area (NCA). The IESO will attempt to make this information available before the end of 2020. The information provided will be for illustrative purposes only and will not constitute an NCA designation for Market Renewal go-live.
605	Offers, Bids, and Data Inputs	Electricity Distributors Association	Generally, we agree with the objectives of the MRP, being to improve economic efficiency, transparency and competitiveness of Ontario's wholesale electricity market that, in combination, are expected to lower electricity costs for consumers. In addition to identifying the required amendments to IESO Market Rules and Market Manuals, we advocate that the IESO, the Ontario Energy Board (OEB), and the Ministry of Energy, Northern Development and Mines (MENDM) proactively engage with LDCs and their customers to identify, scope, evaluate and decide on: • enabling legislative amendments; and • amendments to regulatory policy (e.g., the mechanics of the Regulated Price Plan (RPP), the price that LDC embedded generators are to be paid) and regulatory instruments (e.g., OEB codes including the Distribution System Code (DSC), Retail Settlement Code (RSC), Standard Supply Service Code (SSSC)) that will, in concert, support LDCs as they move forward with implementation of MRP. We also urge the IESO, the OEB and MENDM to appropriately sequence these changes. Given the timeframe of proposed implementation and complexity of the changes, there are natural advantages of convening stakeholder consultations at the earliest opportunity.	The IESO will continue to work with stakeholders, including LDCs and the OEB, so that all parties can understand and implement the changes needed as part of the renewal of the market. We look forward to continuing to collaborate with the EDA and broader sector partners to plan for the changes required to implement Market Renewal.
606	Offers, Bids, and Data Inputs	Electricity Distributors Association	We propose that the participant descriptions provided in this section be updated to reflect the proposed changes identified by the Energy Storage Design Project (ESDP) interim design. Specifically, the descriptions should include the proposed "electricity storage participant" that will be a registered market participant authorized to submit dispatch data (if dispatchable) or schedules (if self-scheduling).	MRP is aware of the proposed changes identified by the ESDP interim design and will incorporate the changes into the draft MRP market rules and market manuals once the ESDP interim design rules are live.

ID	Design Document	Stakeholder	Stakeholder Feedback	IESO Response
608	Offers, Bids, and Data Inputs	Electricity Distributors Association	3.5.4 Network Model Pricing Locations: We recommend that the IESO clarify that NDLs will be priced based on the DAM Ontario zonal price plus the Load Forecast Deviation Charge (LFDC) and that the generalized statement "LMPs will replace the uniform price and be used for settlement purposes" be deleted. While the IESO provides a list of "pricing location definitions that will need to be maintained or expanded as part of the Network Model Build Process", we recommend that the IESO specify the new information requirements. Load Distribution Factors (LDFs): We consider that the IESO's discussion of LDFs requires additional detail and specificity such as: • a detailed explanation of the methodology to calculate LDFs and of the IESO's procedures to ensure the accuracy of the information used in the DAM, PD and RT calculation engines. We note that the DAM Quantity of Scheduled for Withdrawal (DAM_QSW) is determined by the DAM calculation engine and that the DAM_QSW is a key factor in determining the LFDC. • specifying that LDFs are determined for each NDL in the network model, and that dispatch data from dispatchable loads will be used in the network model rather than stating that "LDFs are a set of values that define what percentage of the demand forecast should be assigned to each load facility in the network model." • specifying which demand forecast will be used to produce the LDFs and to ensure that references to (1) demand forecast areas, (2) total demand forecasts, and (3) NDL demand forecasts are applied consistently between sections 3.5.4 and 3.5.6. Additional specificity will augment and clarify the IESO's high-level description that LDFs will be "based on load patterns" from the same day of the previous week, current and last dispatch hour, as applicable, for the DAM, pre-dispatch (PD) and real-time (RT) calculation engines.	The IESO will update the Offers, Bids and Data Inputs design document to identify the prices that apply to different types of registered facilities and separately identify which facility types are existing vs. new pricing locations. The DAM, pre-dispatch and real-time calculation engines provide additional information about how LDFs are calculated and used.

ID	Design Document	Stakeholder	Stakeholder Feedback	IESO Response
610	Offers, Bids, and Data Inputs	Electricity Distributors Association	3.5.6 Demand Forecasts We consider that the IESO's proposed production of NDL demand forecasts and its highlevel descriptions of the new processes that it will implement to produce demand forecasts (e.g., for the four demand forecast areas that will combine to create the province-wide demand forecast) both require further detail. Demand Forecast Areas: We consider that this section lacks sufficient detail to adequately explain the demand forecasting method used for each demand forecast area and the process for automatically adjusting each demand forecast (e.g., for transmission line losses, dispatch data from other loads). We also consider that the IESO should clarify whether it will forecast NDL demand levels for each demand forecast area or on a province-wide basis. Total Demand Forecast Inputs: We consider that the IESO should address ways to increase its forecast accuracy for the deployment of DERs, whether they result in more stable or more volatile load levels. We acknowledge that Ontario already has a significant amount of embedded generation and energy storage connected, but not registered with the IESO and that DERs will continue to be deployed in increasing number and range of sizes (e.g., electric vehicles, storage devices). Whether the IESO over- or under-forecasts NDL demand, including the effects of DERs, risks skewing the market prices for load/supply. NDL Demand Forecasts: We consider that this section will benefit from additional specificity and detail. For example, the IESO could describe: • the outputs that would be associated with each variable used by its DAM calculation engine (e.g., hourly average NDL demand forecast, peak NDL demand forecast for each demand forecast area), and • its methodology for determining the hourly peak NDL demand forecast by area.	The enduring documentation that will be used to provide greater detail about the IESO's future near-term area demand forecast methodology will be shared with stakeholders during the implementation phase. The IESO also acknowledges the importance of accounting for DERs in its area demand forecasts. Exploring new data sets to provide greater DER visibility is planned as part of solution development and testing. Additional specificity about how the IESO arrives at the NDL demand forecast 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).
236	Offers, Bids, and Data Inputs	Emera Energy	The detailed design document mentions in several places that the "Hot, Warm or Cold" status needs to be identified in the DAM submission. Start state can change throughout the day, an hours offline counter to automatically determine start state or an hourly start state selection would be required.	In today's DACP, market participants submit the dispatch data values that best reflect their anticipated start up profiles for tomorrow based on their scheduling expectations for the remainder of the current day. Using an hours offline counter in the DAM could create an undesirable schedule for the market participant since the DAM engine would have to make scheduling decisions for tomorrow based on a current day schedule that can still change. To avoid this situation, market participants will continue to have control over what start up profiles and data values they wish to submit into the DAM for the next day.

ID	Design Document	Stakeholder	Stakeholder Feedback	IESO Response
238	Offers, Bids, and Data Inputs	Emera Energy	Does the IESO intend to allow for hourly selection of simple cycle, intra day? In addition to losing the ST due to a forced outage and/or maintenance during circumstances where there aren't enough hours in the day to satisfy a generators combined cycle start up and MGBRT the generator may elect to offer simple cycle to respond to market conditions, thus providing the system with additional flexibility.	The calculation engines are only capable of evaluating pseudo-unit resources in either simple cycle or combined cycle mode across all hours of any look-ahead period. Hourly selection of modes is not possible. Market participants can still respond to market opportunities and offer their flexibility by changing to simple cycle mode intra-day, provided the pseudo-unit resource has no existing or future commitments in combined cycle mode.
322	Offers, Bids, and Data Inputs	Northland Power	[...] Will resources be able to register different hot, warm and cold leadtimes for summer and winter? Winter conditions may impact lead times.	Yes, registered reference levels for lead time will be established for both summer and winter periods. These periods are described in Section 3.7.2 of the Facility Registration detailed design document.
323	Offers, Bids, and Data Inputs	Northland Power	• In the "Lead Time" section it states "Each lead time value (hot, warm and cold) submitted as dispatch data must be a whole number that is greater than or equal to zero value and less than or equal to 24" Where does the basis for 24 hours originate from? There are some conditions where a lead time may be greater than 24 hours. Will the IESO consider lead times greater than 24 hours if it can be justified?	The maximum value for lead time is limited to 24 hours because the scheduling horizon for the pre-dispatch calculation engine is limited to a single day. In circumstances where a resource's lead time is greater than 24 hours, the market participant should submit 24 hours. The PD calculation engine will then recognize that the resource cannot be scheduled during that particular day.
324	Offers, Bids, and Data Inputs	Northland Power	In the "Lead Time" section it states "The sum of the lead time values (hot, warm and cold) must be less than or equal to the sum of the registered reference level values for lead time (hot, warm and cold) plus 6 hours." What's the basis for the 6 hours? Some facilities are very different when compared to others not only technically but also based on the types of gas services they have procured? How has the IESO already landed on 6 hours without first defining the reference values?	The basis for the 6 hours was informed by practices in other jurisdictions. This threshold, combined with seasonal values for non-financial reference levels, provide flexibility for the market participant to account for variations in operational capability due to changing ambient conditions. The need for additional flexibility to address variations in operational capability should be brought into the reference level engagement.
325	Offers, Bids, and Data Inputs	Northland Power	Related to section Chapter 7 Section 3.5 – section on Lead Time Northland made a recommendation for the IESO to consider adopting a fourth state besides Hot, Warm and Cold in previous discussions with the IESO and would just like to reiterate the value of having a 4th state as "Very Cold" to identify the periods of time where a facility may be offline for an extended period of time. For e.g. if a cold start is one where a resource is offline for 60 hours in the summer, but it's generally expected that the facility may operate shortly after 60 hours, the time to bring that resource backonline is very different than if a resource hasn't been online for 60 days and it's in the winter time. The IESO should at least recognize this difference.	The design provides flexibility for generators to vary their cold state data submissions to reflect 'less cold' or 'colder' conditions between summer and winter. The calculation engines are not capable of evaluating more than 3 thermal states. Providing market participants with the ability to vary their dispatch data for each of the three states is an alternate way to provide similar flexibility. 'Very cold' dispatch data values that reflect 'colder' winter conditions can be submitted as long as those values fall within validation rules for a 'cold' state. These validation rules are provided in the Offers, Bids and Data Inputs design document (Lead time and minimum generation block down time subsections within Section 3.4.2) For example, cold lead time and cold down time values that are shorter than their registered 'cold' reference levels can be used to reflect less cold conditions in the summer as long as the value is greater than the warm data. Longer values can be used to reflect colder conditions in the winter as long as the values do not exceed the lesser of two times the registered cold reference level or the registered cold reference level + 3 hours.

ID	Design Document	Stakeholder	Stakeholder Feedback	IESO Response
612	Offers, Bids, and Data Inputs	OEA	Ontario Energy Association recognizes the effort IESO staff and participants have put into the development of the detailed design documents and appreciates the opportunity to provide feedback on this important program. The Offers, Bids and Data Inputs detailed design document is well organized and reflects most of the comments from participants. In particular the hydro-electric optimization data inputs should provide more efficient operation and market outcomes. Though, it is unfortunate the IESO did not expand the non-quick start generation state to include full speed no load and stone cold states. These additions would provide the participant the opportunity to better represent the physical state of the non-quick start resource.	The design does provide flexibility for generators to vary their hot and cold state data submissions to reflect full speed no load and 'stone cold' conditions. The calculation engines are not capable of evaluating more than 3 thermal states. Providing market participants with the ability to vary their dispatch data for each of the three states is an alternate way to provide similar flexibility. Dispatch data values can be submitted to reflect FSNL conditions and 'very cold' conditions as long as those values fall within the validation rules for a 'hot' and 'cold' state. These validation rules are provided in the Offers, Bids and Data Inputs design document (Lead time and minimum generation block down time subsections within Section 3.4.2). For example, hot lead time and hot down time values of zero can be used to reflect FSNL conditions. This tells the DAM and 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. Longer 'cold' values can be used to reflect 'stone cold' conditions as long as the values do not exceed the lesser of two times the registered cold reference level or the registered cold reference level + 3 hours.
613	Offers, Bids, and Data Inputs	OEA	Section 3.4.2 Generation Facility Dispatch Data to Supply Energy Hourly Must-Run – since this parameter identifies a volume of energy that will generate regardless of the economics of the offer, the offer price should be negative MMCP. Daily Disaptch Data -it is unclear if the Daily Dispatch Data in relation to Pre-Disaptch is date specific or if it covers all hours of Pre-Dispatch. For example, at 20:00 when the Day-Ahead Offers and Bids are imported into Pre-Disaptch, does Pre-Dispatch continue to use the current Daily Disaptch Data when calculating the results for the remaining hours of the current day or is the current day's Daily Dispatch Data overwritten with the new information? Minimum generation block down time (MGBDT) use in Day-Ahead is confusing. Is MGBDT only used if a Non-Quick Start generator has a second Day-Ahead Start? If so, MGBDT should default to "Hot" as almost all second starts within a day will be a "Hot" start. In addition, having the participant identify the state of the resource is almost impossible as the Day-Ahead results will define when the second start is required.	Offer price restrictions are not required to support Hourly Must Run (HMR) submissions since the volume of HMR energy scheduled will not be eligible to set price. For most daily dispatch data submissions, the 20:00 run of pre-dispatch will use Day 0 values for the first 4 hours, and Day 1 values for the remaining 24 hours of the next day. For the remaining daily dispatch data, the 20:00 run of pre-dispatch will use the Day 1 values for the entire 28 hour look-ahead period. The Pre-Dispatch Calculation Engine detailed design document defines which daily dispatch data is used when in Section 3.5.5 Evaluation of Daily Dispatch Data Across Two Dispatch Days. Correct, MGBDT is only used to evaluate second starts in the DAM. The IESO agrees that MGBDT should default to hot when evaluating second starts and will update the design documents to reflect this change.

ID	Design Document	Stakeholder	Stakeholder Feedback	IESO Response
126	Offers, Bids, and Data Inputs	OPG	Review of offers, bids and data inputs in the new market needs to be done in tandem with the review of the calculation engine detailed design documents. The IESO's response to the Publishing & Reporting Detailed Design comments indicates market participants will be given a second opportunity for comments for the Offers, Bids & Data Inputs Detailed Design following the release/review of the calculation engine design documents. OPG further suggests the IESO augments these comments with stakeholder sessions for market participants to discuss their recommendations and/or proposals with each other and the IESO.	As discussed at the engagement sessions, stakeholders will have the opportunity to review and revise feedback once all draft detailed design documents are published. The project reached that milestone on September 30, so stakeholders have the opportunity to submit new feedback applicable to previous detailed design documents resulting from the three calculation engine documents until December 2. Feedback submissions are publicly posted on the Energy Detailed Design Engagement webpage to provide transparency into all stakeholder recommendations and proposals.
127	Offers, Bids, and Data Inputs	OPG	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.	The IESO has hosted a number of technical sessions with the hydroelectric community, among others, as the work to respond to stakeholder advice and finalize 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.
130	Offers, Bids, and Data Inputs	OPG	There are insufficient details in the design document to determine if the new hydro parameters will be effective. Further the design of these parameters may need to be adjusted as other elements of the design are finalized. [...]	As discussed at the engagement sessions, stakeholders will have the opportunity to review and revise feedback once all draft detailed design documents are published. The project reached that milestone on September 30, so stakeholders have the opportunity to submit new feedback applicable to previous detailed design documents resulting from the three calculation engine documents until December 2.
131	Offers, Bids, and Data Inputs	OPG	IESO is currently undertaking initiatives to implement a Storage Design Project (SDP) to allow for Energy Storage Resources (ESRs) to participate fairly within the IESO Administered Market (IAM). During stakeholdering with the Energy Storage Advisory Group (ESAG), it was noted that several design features would be implemented alongside the Market Renewal Project. OPG understands that a decision was made by the IESO to not integrate the long-term SDP with MRP. This decision, although understandable to manage Market Renewal Project scope, will undoubtedly lead to barriers when making necessary changes to ensure appropriate design criteria for ESRs in the future. […] The SDP Interim Design has proposed changes to Market Rules and Manuals ahead of MRP implementation, and therefore these design criteria should be factored into or referenced in MRP, particularly in the Offers Bids and Data Inputs Detailed Design.	Thank you for the feedback. The MRP Energy and Energy Storage Design Project initiatives, while not integrated within MRP, will continue to coordinate any updates as needed to reflect the interrelationship between the projects.
132	Offers, Bids, and Data Inputs	OPG	In Section 2.2.1, the IESO bullets do not include forbidden regions. For additional clarity, OPG suggests the bullet list of new dispatch data features for hydroelectric resources include a bullet describing forbidden regions.	The IESO will update Section 2.2.1 to clarify that forbidden regions are included as new dispatch data.

ID	Design Document	Stakeholder	Stakeholder Feedback	IESO Response
133	Offers, Bids, and Data Inputs	OPG	[...] OPG recommends the IESO provide some form of reporting on the impacts of dynamic loss factors to price & dispatch in order to provide transparency to market participants. […] […] In general, OPG does not support dynamic loss factors updated more frequently than one hour, due to experienced dispatch volatility issues experienced when it was last implemented at market open (2002). […] o Is the IESO suggesting possible different loss factor frequency updates by node? o In OPG's experience, it is not possible to accurately determine whether dispatch volatility will be an issue until the system is live. How does the IESO intend to determine if dispatch volatility will be an issue and if so, how quickly will it be able to adjust its methodology if needed? o It is important for OPG to always have the most updated penalty factors. If penalty factors are updated more frequently than hourly, it will be challenging to optimize dispatch at energy limited resources to benefit the customer.	The IESO will not update loss factors more frequently that one hour for each node so that the intra-hour dispatch volatility observed during 2002 does not re-occur. The DAM, pre-dispatch and real-time calculation engine detailed design documents reflect the decision to use hourly loss factors. The following reports will be provided to market participants so they can map which hourly loss factors were used to determine the corresponding hourly prices and dispatches for their resources. 1. DAM, pre-dispatch and real-time market energy price reports that include the congestion and loss components. The loss factors used by each engine for each hour can be determined from this information. 2. Private reports that provide DAM scheduled quantities, pre-dispatch scheduled quantities and 5-minute real-time dispatch quantities for their resources.
137	Offers, Bids, and Data Inputs	OPG	Similarly from a foundational principle perspective, it is proposed that the forbidden region parameter be designed for use in day-ahead, pre-dispatch, and real-time calculation engines to: • Create feasible schedules representing the operating ranges of hydroelectric units. • Model an increased number of forbidden regions. In the current market there are only three forbidden regions per resource aggregate. OPG proposes this is expanded to at least 8. This would reflect the number of hydroelectric units per resource aggregate, OPG has one resource aggregate containing 8 units and multiple resource aggregates containing 3 or 4 units. • Allow changes based on operating conditions/head and the best efficiency point for operations. […] Based on the above rationale, the following alternate wording for Forbidden Regions is proposed: "Forbidden regions will be a new voluntary daily dispatch data parameter used to represent one or more operating ranges, in MW, within which a hydroelectric generation unit has operational limitations that may cause equipment damage. This includes submission of forbidden regions based on forecast dispatch of each unit and may include operational efficiency points. Registered market participants will only be permitted to submit forbidden region quantities for generation units associated with a dispatchable hydroelectric generation facility that is registered to submit this dispatch data parameter during the Facility Registration process. The number of forbidden regions will be increased to allow each unit on a resource aggregate to model at least one forbidden range."	Five forbidden regions are the maximum number that can be supported by the calculation engines, considering all of the other new hydro-electric dispatch data parameters that have been included in the design. The definition of forbidden regions will not be updated to include unit efficiency thresholds because these are economic preferences rather than physical operating constraints. Market participants can continue to reflect economic preferences through offer quantities and prices as they do in today's market.

ID	Design Document	Stakeholder	Stakeholder Feedback	IESO Response
139	Offers, Bids, and Data Inputs	OPG	To expand upon the above rationale for DEL calculation, inefficient scheduling either above or below the unit's best efficiency point will impact accuracy of Max DEL calculation and may ultimately cause infeasible day ahead schedules allowing scheduling of generation that is at a higher opportunity cost. Although, multiple DELs were part of the DAM high level design, the detailed design does not allow market participants to submit multiple DELs to represent quantities of energy with different opportunity costs. In the DAM high level design (Page 34), the IESO stated: "Environmental and regulatory conditions can limit the amount of water a hydroelectric resource can use to produce energy over the course of a day. The value of this limited hydroelectric energy is based on the principle of opportunity cost, the value of using limited water to produce energy at a particular time at a given price or saving it for future use at higher prices. Often, a hydro resource's daily energy limit can consist of multiple quantities of water with different opportunity costs. Quantities of water that must be used in the short term (e.g., run-of-riverwater) will have a relatively lower opportunity cost compared to water that can be stored in a forebay for future use at times of potentially higher prices. Enabling multiple DELs to represent quantities of energy with different opportunity costs should result in a more accurate representation of costs and improved resource optimization within the DAM and pre-dispatch engines." OPG proposes the IESO reinstate the DAM high level design decision to enable multiple DELs to represent quantities of energy with different opportunity costs in the day ahead calculation engine. The ability to revise offers and MIN/MAX DEL during dispatch days as conditions change lessens the need for multiple DELs in the predispatch calculation engine.	The DAM engine is not capable of evaluating multiple DELs with different opportunity costs considering all of the other physical operating constraints being introduced for hydroelectric resources. The objective of the expanded set of hydro dispatch data was to capture physical operating constraints to produce feasible day-ahead schedules. Since multiple DELs and associated opportunity costs reflect economic preferences and are not required to produce feasible day-ahead schedules, physical operating constraints took priority. With physical operating constraints respected in the DAM, market participants have greater flexibility to adjust their offer quantities and prices to reflect economic preferences.
141	Offers, Bids, and Data Inputs	OPG	In Section 3.4.2 on Maximum Number of Starts per Day, the design states: "The maximum number of starts per day (MNSPD) parameter will continue to be defined as the maximum number of times a generation unit can be started within a dispatch day." […] As per OPG's earlier comment, the generation unit terminology confuses how this parameter is applied and requires clarification. […] OPG recommends the maximum number of starts per day is assessed 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 or another solution that is transparent for Market Participants. […] It is recommended the IESO re-assess the value of 24 starts per day depending on whether MNSPD is at the resource type level or the unit level.	The design does allow for market participants to manage maximum number of starts per day 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 hours. 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 resources is less than or equal to 24 x the number of units in the aggregate. Stakeholders can refer to the November 14 hydroelectric dispatch data engagement materials for illustrative examples on the application of the maximum starts per day parameter.

ID	Design Document	Stakeholder	Stakeholder Feedback	IESO Response
143	Offers, Bids, and Data Inputs	OPG	In the sub-section describing "Linked Resources, Time Lag and MWh Ratio", the design refers to linkages between resources on hydroelectric cascade river systems. The IESO should clarify what exactly is meant by resources in the context of Linked Resources, Time Lag and MWh Ratio parameter and whether it refers stations or individual aggregates (or both). It is OPG's understanding that the parameter will be applied at the station level.	The linked resources, time lag and MWh ratio parameters can be applied at the resource level or station level. The IESO will update the Offers, Bids and Data Inputs detailed design document to provide greater clarity.
144	Offers, Bids, and Data Inputs	OPG	[...] Hydroelectric generation facilities typically have multiple generation units offered to the market on a resource aggregate/injection point. The IESO use of "Generation unit" as a defined term becomes confusing in subsequent sections and other detailed design documents when hydroelectric facilities have multiple generation units. This makes it increasingly difficult to assess whether dispatch data parameters apply to the resource type level or the generating unit level. For instance, the maximum number of starts per day needs to be defined as either unit level or resource level.	Dispatch data submissions will continue to apply to the resource type level, which can represent one or more generating units. The resource type designations of generating unit and pseudo-unit used in the Offers, Bids and Data Inputs design document mirror the designations that market participants see in the current online offer submission tool. The IESO will update the design document to replace references to generation unit with generation resource.
147	Offers, Bids, and Data Inputs	OPG	[…] The IESO should engage Market Participants in technical discussions, workshops, and one-on-one discussions to determine the types of supporting documentation that will be required [to register an hourly must-run quantity] and develop a review process for this documentation. Depending on the criteria established by IESO for supporting documents, this may be a costly undertaking for Market Participants.	The IESO will simplify the registration in order to reduce the complexity of the supporting documentation that market participants will need to provide. Instead of registering hourly must-run quantities, market participants will simply register the ability to submit the hourly must-run parameter as dispatch data. The supporting documentation will balance the IESO's need to verify that the resource has an hourly must-run requirement with what market participants are reasonably capable of providing.
148	Offers, Bids, and Data Inputs	OPG	There is a discrepancy in Offers Bids and Data Inputs Section 3.4.2 and Grid & Market Operations Integration Section 3.7.2.2 and Section 3.4.2 should be updated to be consistent with Grid & Market Operations Integration Section 3.7.2.2. OPG recommends that Hourly Must Run submissions be respected in the real-time calculation engine. […]	The IESO will update the Offers, Bids and Data Inputs detailed design document to reflect that the hourly must run quantity is also an input into the real-time calculation engine.

ID	Design Document	Stakeholder	Stakeholder Feedback	IESO Response
149	Offers, Bids, and Data Inputs	OPG	The design states: "The PD calculation engine will determine which one of the three MGBDT values to use based on the number of hours the generation unit has been offline. A NQS generation unit will be considered offline by the PD calculation engine if it is scheduled below its MLP value by the PD calculation engine." Using predefined MGBDT values to determine if Hot/Warm/Cold dispatch data applies for pre-dispatch calculation may not accurately reflect the condition of a plant. The condition of thermal plants can vary start-to-start, and thus modifications to hot, warm and cold lead times may be necessary during the day. The thermal state of a NQS unit is determined by its turbine temperatures and can only be accurately determined by the unit operator. OPG requests the IESO publish an hourly standardized confidential report to indicate the inferred state of the generation unit and suggests that a mechanism or process be put in place that allows modification of the Lead Time parameter for SEAL and operational reasons to ensure the accurate thermal 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 the Publishing and Reporting detail design document. The design allows market participants to modify the Lead Time parameter subject to revision rules as outlined in Section 3.3.7.6 of Grid and Market Operations Integration detail design chapter.
150	Offers, Bids, and Data Inputs	OPG	Ramp UP Energy to MLP should allow for units that have multiple ramp up hours to MLP to submit differing values for each RAMP UP hour. For example, HE12 - 20 MW and HE13 - 200 MW should not need to be represented by 110 MW (the average) for each hour. From this example, the use of average causes discrepancies and market inefficiencies in both hours that is avoidable by allowing two separate values. OPG suggests the IESO be explicit that OR will not be scheduled on a resource during the RAMP UP to MLP period.	The design allows for different energy quantities to be submitted for each ramp hour, not a single average value for each hour. The Ramp Up Energy to MLP section of the design document will be updated to provide greater clarity. The DAM and PD calculation engine design documents reflect that operating reserve will not be scheduled on a resource during the ramp up to MLP period.
153	Offers, Bids, and Data Inputs	OPG	[...] The IESO's omission of the ability to declare entire load as non-dispatchable by having no bid at the market reduces market participant flexibility and may limit participation in the Day Ahead Market.	The IESO will update the Offers, Bids and Data Inputs and Grid and Market Operations Integration design documents to reflect that the no bid option for dispatchable loads will be retained in the future market.
155	Offers, Bids, and Data Inputs	OPG	[...] OPG would like clarification if following the DAM, and if market participants modify their DAM cleared import/export offers/bids earlier than 3 hours ahead of real-time, will the revised offers/bids be used in the predispatch runs? [...] Will the pre-dispatch runs use the revised offers once they have been entered or will the IESO wait to evaluate them until they fall within the 3-hour ahead timeframe? It is proposed that the pre-dispatch engine should be able to incorporate all revised bid/offer data for DAM cleared imports/exports in all pre-dispatch runs, including those earlier than 3-hours ahead.	Yes, market participants will be able to revise price-quantity pairs for the import offers and export bids have a corresponding DAM schedule. The PD engine will evaluate these changes in all pre-dispatch runs up to the MW quantity that was scheduled in the DAM.

ID	Design Document	Stakeholder	Stakeholder Feedback	IESO Response
163	Offers, Bids, and Data Inputs	OPG	[…] OPG does not support dynamic loss factors be updated more frequently than hourly due to experienced dispatch volatility issues when it was last implemented at market opening. In particular, the use of dynamic loss factors will make it challenging to maintain relative dispatch order for hydroelectric resources on a cascading river system. […] If the IESO continues to pursue the use of dynamic loss factors in calculation engines, the IESO should perform analysis during sandbox testing and after GO-Live to determine whether the use of dynamic loss factors increases the number of dispatches to resources and has a roll-back plan if the number of dispatches increases or the quality of dispatches degrades. The real-time calculation engine will need to allow for compliance aggregation without potential for the engine to continually re-dispatch resources. […]	The IESO will not update loss factors more frequently than one hour. The DAM, pre-dispatch and real-time calculation engine detailed design documents reflect this decision. The IESO is committed to evaluate the impact on dispatch volatility during solution testing.
164	Offers, Bids, and Data Inputs	OPG	Please provide clarification on the following statement in paragraph 2 of the Load Distribution Factors(s) sub-section: "In the future energy market, the DAM and PD calculation engines will also use LDFs that are based on load patterns from the same day in previous weeks, for all hours except the first two hours of the PD calculation engine's look-ahead period." Following a stat holiday (e.g. the Friday after good Friday), or following a week/day with extreme weather or other circumstances, OPG recommends the IESO make exceptions to this rule to find a more suitable "similar" day.	LDFs based on load patterns from the same day in previous weeks means that the final LDFs used for a particular hour of the DAM and PD engines are determined by blending historical load patterns on the same day from last week with load patterns from the same day in previous weeks. Historical LDFs provide a reasonable expectation of relative load distribution between load locations, even during holidays. The IESO accounts for hourly load profiles that are unique to holidays and extreme weather days via the demand forecast.
221	Offers, Bids, and Data Inputs	OWA	The design requires 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 (MPs) and IESO.	The derate reporting obligations and exemptions that exist today are not changing in the future market. Market participants will continue to be exempt from reporting derates if the derate is less than the greater of 2% of rated output or 10 MW.
227	Offers, Bids, and Data Inputs	OWA	The "forbidden zone" concept is one forced in part by "Market" construct and in part by modern turbine designs. Forbidden zones (aka "rough zones") are typically narrowly defined, will change with gross and net head and are therefore dynamic in nature. Defining these zones in the Market Registration system will remove this dynamic aspect. An alternative may be to specify set operating points (granular dispatch point) rather than leaving a permissible range between price points.	The design allows for market participants to submit more narrowly defined forbidden region data into the market to account for dynamic changes in physical operating conditions. The requirement in today's market where forbidden region data must fall between price points has been removed. Registered quantities are only required to place a boundary on the maximum range that can be submitted into the market as dynamic dispatch data.
228	Offers, Bids, and Data Inputs	OWA	Additional clarity is required on the method by which the IESO will de-rate a unit/plant for hydrology changes and impact on DA commitment. For example, a storm hits with intensity well above forecast, drastically higher flows cause loss of output on loss of head. There are options around this but (1) they risk running afoul of other Market Rules around withholding of capacity or (2) place an undue economic burden on the Generator when it can't meet its DA commitment for reasons outside of his control. One possible solution is expansion of the SEAL criteria to include weather related environmental issues.	As with today's market, it is the responsibility of the market participant, not the IESO, to reflect unavailable energy via offer quantities, energy limited dispatch data and outage/derate submissions in the future market.

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230	Offers, Bids, and Data Inputs	OWA	Non-dispatchable market participants request the IESO's assurance that: a. they preserve the ability to continue to do standing orders for bids/offers; b. they maintain their same abilities to be a self-scheduled plant with no incremental restrictions; and c. any notifications or requests to come online/offline/change output are the same as they are now so there are no additional burden on operations.	The existing dispatch data submission and communication requirements for self-schedulers will be maintained in the future market. There are no incremental changes.
491	Offers, Bids, and Data Inputs	Power Advisory	[…] Considering the scope of the planned MRP reforms to the IAM, IESO should provide process clarity and details regarding these important aspects relating to finalizing MRP detailed design documents. • How will IESO review and provide feedback on all comments received from MPs and stakeholders? • Will specific stakeholder engagement consultations be created to work through MRP detailed design, in addition to plans to engage MPs and stakeholders on the reference levels and reference quantities within the proposed market power mitigation framework, where MPs and stakeholders may not be aligned with each other and/or IESO (even only for design aspects that reveal to be contentious) and/or more time is needed to work through very technical design aspects? • How will disagreements on MRP detailed design be addressed to satisfactory solutions and conclusions, even after specific stakeholder engagement consultations may have been created and administered by IESO? • What will be the process to amend MRP detailed design documents going forward? […] If the above points are not workably addressed, the timelines to finalize the MRP detailed design could be delayed, which could then jeopardize the planned 2023 implementation of the entire MRP initiative.	As indicated in previous stakeholder engagement discussions, the IESO will be posting all feedback that stakeholders have provided, and will be itemizing and responding to all comments within that feedback. As we approach the end of the engagement on Detailed Design, the IESO will be providing a design-change tracker to show all of the updates made to the Detailed Design documents as a result of stakeholder feedback. Further, the IESO will provide a revised version of the Detailed Design documents, and a list of items that will need carried over into the implementation phase to address. The engagement on the Reference Levels and Reference Quantities is underway, which is a venue to discuss the technical aspects of these values, in advance of the IESO proposing rules and manuals, for further stakeholder comment. The IESO has also announced the intent to engage to determine a dispute resolution mechanism for Market Power Mitigation. The IESO is currently working to incorporate stakeholder feedback into the detailed design, and provide transparent rationale if there are cases where stakeholder feedback cannot be fully accommodated. Ultimately, by having an open, transparent and collaborative process with stakeholders serve to bring forward the best design for the Ontario market, and resolve any disagreements on key design elements.
495	Offers, Bids, and Data Inputs	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 to 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 scoped stakeholder engagement only relating to establishment of reference levels and reference quantities […]	Thank you for your feedback. The IESO will take this input into consideration when determining the appropriate future engagement for MRP.

ID	Design Document	Stakeholder	Stakeholder Feedback	IESO Response
496	Offers, Bids, and Data Inputs	Power Advisory	[…] the Consortium is still of the opinion that integrating multiple energy storage technologies (including 'hybrid' storage and VGs) should be in scope for MRP […] However, the Consortium acknowledges declarations made by IESO […] that integrating energy storage resources (other than for the already existing pumped hydroelectric generation station) within MRP will not be in scope […] Considering this IESO declaration, the Consortium recommends that IESO clearly define future commitments to integrating multiple energy storage technologies within IESO systems and tools (including the network model) that will robustly enable scheduling, dispatch, pricing, and settlements within the IAM.	The MRP Energy and Energy Storage Design Project initiatives, while not integrated within MRP, will continue to coordinate any updates as needed to reflect the interrelationship between the projects.
65	Offers, Bids, and Data Inputs	Power Costs	Are bids to consume energy by Price Responsive load are financial deals in Day ahead market in an effort by load to lock in day ahead prices (Like Demand Bid in PJM /ISONE Markets)?	Yes, price responsive loads only submit bids into the day-ahead market and are able to lock in a day-ahead price if they are scheduled in the day-ahead market.