# IESO Response to Feedback on MRP Energy Detailed Design Documents – Real-Time Calculation Engine

Below are the IESO's responses to stakeholder feedback on the Real-Time Calculation Engine detailed design document. The feedback is organized alphabetically by stakeholder.

| ID | Stakeholder | Feedback | IESO Response |
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| N/A | Multiple | Multiple stakeholders asked for examples, scenarios, and walkthroughs of the detailed design. | The IESO has been working with stakeholders collaboratively through the Detailed Design discussion, to further the understanding of stakeholders, and provide background, clarification, and rationale where needed. Further, the IESO has focused on providing background and examples to stakeholders, both in writing and in various stakeholder forums, that answer specific requests. The IESO and stakeholders recognize that the transition to a renewed market can bring forward many requests for scenarios or examples on the impacts on participants, and the IESO will aim to respond to these requests that provide the greater value to the broad stakeholder community, and provide the greatest efficacy. Stakeholders are also encouraged to engage resources to provide them strategic advice on to navigate the nuances of their participation in the renewed market. |
| 716 | Electricity Distributors Association (EDA) | We support the objectives of the MRP - being to improve economic efficiency, transparency, and competitiveness of Ontario's wholesale electricity market – and we understand that they are expected to lower electricity costs for consumers. However, we question if the IESO has publicly provided clear analysis of how the proposed use of Locational Marginal Prices (LMPs) will impact stakeholders. The EDA anticipates the new scheduling, commitment and dispatch processes that are based on LMPs will contribute to lowering wholesale electricity costs. The EDA also points out that charging load customers at prices that are based on LMPs will raise inequities: some load customers may perceive that they enjoy a benefit and others that they are disadvantaged for reasons beyond their control and because of decisions taken by other parties in past periods. The EDA acknowledges that the IESO's current pricing methodology results in cross-subsidies and that pricing supply to consumers using LMPs may overcome them. We seek a clear stakeholder analysis from the IESO of the proposed use of LMPs, with special attention to how LMP based commodity prices will impact end users. To be clear, stakeholders will need to be analyzed at the class level, locationally, according to whether they have control over the infrastructure that serves them with commodity supply and other factors. | The IESO described the benefits to Ontario consumers of moving to an Locational Marginal Pricing (LMP) pricing regime during the High-Level Design phase of Market Renewal. At the July 2018 stakeholder engagement session the IESO provided materials that outlined how locational pricing can reduce wholesale energy costs compared to the current uniform price system. That information can be found beginning on slide 13 in the July 2018 engagement materials.<br><br>As Market Renewal advances, we continue to connect with stakeholders to talk about the new and revised reports, and market data, to arm market participants with the best available information to make decisions. |

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| 717 | Electricity Distributors Association | Below is the EDA's high level synopsis of its previous submissions that are relevant to this submission.<br>We repeat that, in addition to identifying the required amendments to IESO Market Rules and Market Manuals, the IESO, the Ontario Energy Board (OEB), and the Ministry of Energy, Northern Development and Mines (MENDM) should proactively engage with LDCs and their customers to identify, scope, evaluate and decide on enabling legislative amendments, amendments to regulatory policy and amendments to regulatory instruments. […]<br><br>We also repeat our proposal that each Detailed Design produced by the IESO consistently apply terminology and defined terms. For example, within the Real-Time (RT) Calculation Detailed Design, the IESO uses the following terms interchangeably:<br>• "real-time hourly Ontario zonal price"<br>• "RT Ontario Zonal Price"<br>• "zonal prices"<br>As the EDA commented in its feedback on the Market Settlements Detailed Design on July 31, 2020, the IESO should use standardized terms correctly and consistently so that confusion is avoided, the usability of the documents is improved and gap analysis is facilitated. | Thank you for the feedback. The IESO will continue to work closely with stakeholders, including the Local Distribution Company (LDC) community, throughout the Detailed Design and Implementation phases to address these issues as proactively as possible, and will take this advice under advisement.<br><br>Regarding the feedback on terminology, the IESO will amend V2.0 of the Real-Time Calculation Engine detailed design document to use this terminology consistently. |
| 719 | Electricity Distributors Association | […] We suggest that a mapping of the outputs of the RT Calculation Engine to the IESO's market settlement processes and to market participants' settlement processes will improve the Summary.<br><br>We suggest that the IESO ensure consistency of terminology in this section relative to other Detailed Design documents. For example, the IESO uses the term "load forecast adjustment of the DAM hourly zonal price" as opposed to the defined term per the Market Settlement Detailed Design which is "Load Forecast Deviation Charge (LFDC)". We note this recommendation is also applicable to section 3.6.2 as well. | Please refer to Section 3.6.3 of the Real-Time Calculation Engine detailed design document for details on outputs from the Real-Time (RT) calculation engine that will be utilized for settlement.<br><br>Regarding the feedback on terminology, the IESO will amend V2.0 of the Real-Time Calculation Engine detailed design document to use this terminology consistently. |
| 720 | Electricity Distributors Association | We consider that this section provides a detailed description of the proposed RT Market's functions, calculations, and outputs. Consistent with our feedback on the DAM Calculation Engine, we agree with other stakeholders who commented at the IESO's August 27, 2020 webinar that the inclusion of worked examples will improve all parties' understanding of the Detailed Design.<br><br>We characterize the Detailed Design as incomplete as it does not reference changes proposed by the interim design of the IESO's Storage Design Project. For example, the IESO does not include references to 'electricity storage participants' per MR-00445-R00- R05 ('Implementation of the Interim Storage Design'), which is currently being reviewed by the IESO's Technical Panel in preparation for consideration by the IESO's Board of Directors, the final step in the Market Rule amendment process. | The Market Renewal Program (MRP) Detailed Design is focussed on the design changes that are a direct result of introducing a single schedule market, a day ahead market, and an enhanced real-time unit commitment. MRP is aware of the proposed changes identified by the Energy Storage Design Project (ESDP) interim design and will incorporate the changes into the draft MRP market rules and market manuals once the ESDP interim design rules are live. |

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| 721 | Electricity Distributors Association | Section 3.2 Objectives<br>The IESO notes that nodal and zonal prices will provide more accurate pricing signals and improve incentives for market participants to submit offers at marginal costs. We seek confirmation that the IESO considered the unique characteristics of the Ontario electricity sector (e.g., contracted resources, rate-regulated resources, Global Adjustment cost allocation) in this Detailed Design. As demonstrated elsewhere in this submission (refer to Section 3.8 below), reforms to the wholesale market must consider the interplay of out-of-market payments to generators and the implications for consumers who respond to price signals that recover such out-of-market costs. | As the IESO moves ahead with Market Renewal, we are taking into account the unique characteristics of the province, and will proceed by working closely with stakeholders. One of the goals of Market Renewal is to improve the clarity and transparency of price signals within the wholesale market. There are no plans to move out-of-market costs to be recovered by a different method in the renewed market, but we will work with stakeholders through the Implementation phase to show the rules and manuals that will govern settlement. |
| 722 | Electricity Distributors Association | Section 3.6.3 Outputs for Energy and OR Settlement<br>We request that the IESO clarify whether proxy buses will be used as price setting locations (i.e., included as an internal price setting node). This concern arises when Table 3-9, that defines the variable "FHDR" as the fixed schedule of energy consumption for the interval for physical or virtual hourly demand response (HDR) resources at a bus, is read in conjunction with section 3.4.1.3, that states that virtual HDR schedules will be defined by a 'proxy bus'. | LMPs for virtual Hourly Demand Response (HDR) resources will be calculated at their proxy buses. |
| 723 | Electricity Distributors Association | Section 3.7.1.2 Security Limits (re: NDL quantities)<br>We observe that this section lacks specificity. We recommend that the IESO provide more detail as well as worked examples (e.g., on the quantification of NDL quantities).<br><br>This section describes that the IESO will use load distribution factors (LDFs) to allocate the IESO demand forecast among each of the four demand forecast areas. The IESO then backs out the forecast NDL demand levels to determine the MWs required by the PRL in the forecast area. We understand that the resulting price data are key inputs for price formation. The IESO proposes to further adjust the demand data by pro rating LDF data to reflect IESO control decisions. We seek worked examples prepared by the IESO to assure itself that it has understood the process correctly and to understand how the data that will be essential to price formation is derived. | 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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| 724 | Electricity Distributors Association | Section 3.8 Pricing Formulas (re: settlement price floor)<br>The IESO proposes to continue to rely on the current minimum price for bids and offers from active market participants of -$2000/MWh and to modify any LMPs that are between this level and -$100/MWh to -$100/MWh.<br><br>A lower settlement price floor will result in lower LMPs which, all other things being equal, will increase the Global Adjustment (GA). While Class A customers will be able to control their GA responsibility, Class B customers cannot. Class B customers risk a combined lower commodity price and a higher Global Adjustment. We seek to confirm its expectation and propose that the IESO provide:<br>• its analysis of the impacts to Class A and Class B customers of the proposed design decision on settlement price floors<br>• a description of how the IESO used this analysis when adopting the design decision and subsequently when the IESO the quantified threshold values.<br><br>We seek additional information on the IESO's design decision for the -$100/MWh settlement price floor including:<br>• how often does IESO anticipate the need to adjust or modify prices?<br>• which locations in the province are anticipated to be impacted by the modification of prices to the settlement floor?<br>• whether the settlement price floor creates advantages or disadvantages for certain resources<br>• whether the IESO will publish modified as well as un-modified prices?<br><br>We look forward to better understanding the impact of adjusted prices to consumers, whether Class A of Class B. | In its stakeholder engagement material from November 2017, the IESO presented analysis regarding the frequency of negative prices in each of Ontario's electrical zones. That analysis showed that the frequency of locational prices that were substantially negative was less than 0.1% of intervals in Southern Ontario, roughly 2% of intervals in Northeastern Ontario and approximately 10% of intervals in the Northwestern region of the province. The information can be found on slide 44 of the meeting materials.<br><br>The IESO will publish energy prices that are within the settlement bounds of +$2,000/MWh to -$100/MWh. Prices that are outside of the settlement bounds will not be published.<br><br>Not modifying substantially negative prices would significantly depress locational prices in regions where oversupply is most common; such as Northwestern Ontario. Very low locational prices could mean that exports in the northwest would be paid up to $2,000/MWh to purchase power from Ontario. The suppliers of that power would be largely shielded from the -$2,000/MWh energy price by the terms of their contract or regulated rate. The net effect would be a depressed local energy price, increased profits to exporters, a higher global adjustment, and subsequently, higher costs to Ontario ratepayers. |
| 725 | Electricity Distributors Association | Section 3.8 Price Formulas (re: weighting factors)<br>The IESO states that it will use weighting factors derived by renormalizing LDFs to calculate prices in NDL zones and that the sum of the weighting factor for an individual zone will be set to one. We seek improved clarity (e.g., worked examples) of the derivation of renormalized LDFs and of how renormalized LDFs are used in subsequent calculations, including the derivation of the RT LMPs. | Load distribution factors (LDFs) are percentages provided for all load resources, with each resource's LDF representing its share of total Ontario load. Since non-dispatchable load (NDL) zonal prices will be derived only from NDL resources, for the purposes of pricing the LDFs for NDL resources will need to be renormalized. |
| 726 | Electricity Distributors Association | Section 3.8.1.3 Zonal Energy Prices<br>We seek to clarify that the RT Ontario Zonal Price will not be used for NDL settlement purposes. The IESO should clarify the use of the RT Ontario Zonal Price by mapping to the IESO Market Settlement Detailed Design or other IESO processes. | The RT Ontario Zonal Price will not be used for NDL settlement purposes. It will be published only for informational purposes. |
| 727 | Evolugen | As a general recommendation, we suggest that the IESO use the same Time Zone for both the DA and RT calculation engines, be it EPT or EST. | The solution results from both the Day-Ahead Market (DAM) and RT calculation engines will continue to be in Eastern Standard Time (EST). |

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| 728 | Evolugen | Section 3.4.1.4 mentions that the RTCE will evaluate hydroelectric generators' forbidden regions, Hourly Must-Run and Minimum Daily Energy Limit, but what about other the hydro-specific data inputs? Is it possible that the RTCE would override or ignore the Max Daily Energy Limit or the Linked Resource/Time Lag/MWh Ratio parameters? | The real-time calculation engine will be provided with constraints for Hourly Must Run and minimum daily energy limits. The remaining hydroelectric-specific parameters will not be constraints in the real-time calculation engine. In the case of the maximum daily energy limit, this is consistent with the current real-time calculation engine. The constraints implied by the max daily energy limit and parameters associated with cascade resources do not become fixed or definite until the resource actually generates; the resource remains dispatchable in real-time for their available capacity.<br><br>As today, there is the possibility for RT to deviate from the expectations of DAM and pre-dispatch (PD) for a quick-start hydroelectric resource given the most current operating conditions in real-time. As today, market participants may continue to manage these changes through offer structures, river and compliance aggregation, and if required, requests for manual actions from the IESO. Should conditions prior to the dispatch hour remove a resource's ability to be fully dispatchable in real-time, market participants may use the Hourly Must-Run constraint to reflect the need in real-time.<br><br>IESO has responded to a similar feedback item in the Offers, Bids and Data Inputs detailed design document on December 2 2020. Please refer to item #142 for more details. |
| 729 | Evolugen | Generators providing AGC will not be allowed to offer Operating Reserve in the RT market, therefore the RTCE will not schedule OR for a resource nominated to provide AGC.<br><br>Please clarify if this only applies to the hours where AGC has been awarded, or if it affects the whole day. | As today, generators providing Automatic Generation Control (AGC) will not be allowed to offer operating reserve in the real-time market in the hours they are providing AGC. The real-time calculation engine is able to schedule operating reserve on these resources in hours where no AGC is being provided.<br><br>The IESO will amend V2.0 of the Real-Time Calculation Engine detailed design document to further clarify this point. |
| 730 | Evolugen | Regarding tie-breaking (Section 3.4.1.5), when two or more bids/offers for energy or OR are the same and do not create differences in the optimization runs, we understand that the tie will be broken in one of two ways:<br>1st method: For variable generators only, the daily dispatch order for VG will be used<br>2nd method: Used for all bids/offers for energy or OR, the tied offers will be pro-rated based on the amount of energy offered<br><br>Please provide additional information, for example on how this would be affected by units' minimum generation levels, hourly must-run, forbidden regions, and/or other existing or upcoming operational parameters. | As today, tie-breaking rules will be used in real-time when there exist two or more equivalent energy offers, or resource constraints, such as Hourly Must-Run or Forbidden Regions, that do not create differences in the optimization. |

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| 731 | Evolugen | Regarding Settlement Price floor: the proposed settlement price floor (-$100) does not financially incentivize hydro generators to reduce output and risk spilling their fuel. This in turn does not help the IESO reduce Surplus in the zone or region. It also eliminates "price separation" below the -$100 settlement threshold that the IESO count on for managing surplus conditions. Please address these concerns. | A settlement floor of -$100/MWh will result in a charge of $-100/MWh to any supplier seeking to provide energy into an oversupplied area of the grid.<br><br>There will be no change to the existing offer floor of -$2,000/MWh, participants will continue to be able to offer below -$100/MWh to manage their operations. This solution, the settlement price floor, was designed so it will not interfere with dispatch. |
| 715 | HQEM | As previously indicated in past comments, HQEM wants to reiterate its position against the treatment of imports decision published in the high-level design in August 2019, as well as in the current detailed design document.<br><br>The proposed treatment is the following: […] If an intertie is export-congested, the intertie settlement price will be the sum of the real-time intertie border price and the pre-dispatch intertie congestion price. If an intertie is import-congested, the intertie settlement price will be the lesser of the pre-dispatch intertie price and the real-time intertie border price. In instances where the intertie is congestion free, the intertie settlement price will be equal to the real-time intertie border price. […]<br><br>As the largest energy importer for Ontario, HQEM still considers that this treatment is particularly unfavorable, in comparison with the treatment proposed for exports. In recent years, approximately 70% of the total imports made by the IESO has been supplied by HQEM.<br><br>HQEM is aware that this treatment will only apply to real-time transactions. HQEM would be in favor of a more uniform treatment for settlements, where imports and exports would be evaluated on a same level. The current proposal involves that, in theory, two transactions could occur at the same node, and have each one of them, a different treatment, depending if it's an import or an export.<br><br>Also, this treatment will apply to linked wheel transactions, which HQEM also commented on January 13th 2020.<br><br>Imports in the market should be treated on the same basis as exports. It is important to mention that imports coming in Ontario have a purpose to help cover the energy needs and reliability of the system. | Thank you for your feedback. As communicated during high-level design, and in responses to similar feedback in previous design topics, the decision regarding import congestion pricing in real-time is expected to lead to more efficient intertie offers and pricing outcomes. |

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| 733 | OPG | OPG made several detailed recommendations to improve the design of the new hydroelectric parameters in its review submission for the Offers, Bids and Data Inputs design section. This included recommendations for alternative wording to:<br>• Minimum hourly output (MHO)<br>• Forbidden regions<br>• Daily Energy Limits (DELs)<br>• Maximum Number of Starts Per Day<br>• Linked Resources, Time Lag and MWh Ratio<br><br>The IESO has not yet provided any feedback on these recommendations in its responses posted on October 19, 2020 stating that feedback for the remaining comments would be provided in November. OPG may have additional comments on the calculation engine detailed designs once IESO has provided feedback on these previous recommendations. | The IESO is thankful to all stakeholders for the detailed and constructive feedback we have received. The IESO posted comprehensive responses to stakeholder feedback on the Offers, Bids, and Data Inputs, Grid and Market Operations Integration, Market Power Mitigation, and Market Settlement detailed design documents in two batches. The first batch was posted on October 19, 2020 and the second batch on December 2, 2020. |
| 734 | OPG | The design document does not provide any information on how Operating Reserve Activations (ORAs) will be treated. Some details that the IESO should provide include:<br>1. How does the calculation engine determine whether an ORA is needed?<br>2. How does the calculation engine determine which resources to activate and to what MW output?<br>3. Describe the interaction (if any) between ORAs and the pricing algorithm. | Consistent with today's market, the calculation engine does not determine whether an Operating Reserve Activation (ORA) is needed, which resources to activate, or what megawatts (MWs) are required. ORAs will continue to be managed by the IESO through a manual process. |
| 735 | OPG | When IESO makes significant (e.g. ±100 MW) changes to zonal demand and variable generation forecasts inside the mandatory window, it can have a significant impact on market results, without giving an opportunity for market participants to respond to these signals. OPG suggests that when IESO adjusts a forecast inside the mandatory window, they open the mandatory window for market participants to adjust offers/bids accordingly, to drive better market efficiency. | The IESO considered the cost, effort, and impact to project schedules associated with customizing the engines to increase the flexibility of the mandatory window, along with the benefit to market participants and the IESO. While this initiative is an important consideration to intertie traders and internal generators, it will not be included within the scope for the Market Renewal – Energy project. |
| 736 | OPG | OPG included a comment proposing that the duration of the RT Mandatory window be reduced from 110 minutes to 90 minutes in its review submission for the Grid and Market Operations, Integration Design. The IESO did not provide any feedback to this proposal in its review comment responses posted on its website on October 19, 2020. OPG has reproduced its previous comment below and encourages the IESO to adopt this proposal:<br><br>"Figure 3-2 shows the real-time market (RTM) Mandatory Window as 110 minutes. The IESO should consider shortening the RTM mandatory window time frame from 110 minutes to 90 minutes. A shorter window would be beneficial to market participants as it would provide resources additional flexibility / time to adjust to offers based on changing conditions (e.g. hydroelectric flow, forced outages etc.). In NYISO, the mandatory window is only 75 minutes." | A response to the referenced Grid and Market Operations Integration feedback was posted on December 2, 2020 under ID #336. |

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| 737 | OPG | In section 2.1.3 the design states:<br>"In certain circumstances, the actual dispatch instructions are different from the outputs of the DSO runs. These circumstances can arise when the IESO needs to intervene with the outcome of the dispatch algorithm by modifying or overriding the dispatch instructions for reasons related to system reliability. In such cases, prices and dispatch might not be aligned and may result in CMSC payments."<br><br>The IESO should explicitly state whether they expect the circumstances above to exist after market renewal and provide examples of how market participants will be aware of these situations, market power mitigation is enforced, and how market settlement is impacted. | As stated in sections 3.8.7 and 3.8.11 from the Grid and Market Operations Integration Detailed Design Document, the IESO will continue to intervene in real-time dispatch when required for reliability. These manual interventions are considered reliability constraints and are eligible for real-time make whole payments, subject to mitigation according to reliability constraint conduct and impact thresholds. Grid and Market Operations Integration v2.0 will clarify this detail. |
| 738 | OPG | In section 2.2.1 the design states:<br>"Five-minute demand forecasts will continue to be used as an input for the expected load in the RT calculation engine. However, the IESO will now produce the existing province-wide demand forecast as the sum of four separate demand forecast areas."<br><br>The IESO should provide an example of how the existing province-wide demand forecast is produced as the sum of four separate demand forecast areas. | The existing province-wide demand forecast will no longer be utilized in the future market. The province-wide forecast will be determined by summing the four demand forecast areas. |
| 739 | OPG | […]<br><br>The IESO should provide a detailed example that illustrates the difference between constraint violation penalty curves for pricing and reliability and the impact on settlement ready LMPs and shadow prices. | Materials prepared in advance of the November 2019 technical session on constraint violation pricing contains information describing how constraint violation penalty curves can differ between the scheduling and pricing steps of the relevant calculation engine. Details can be found in the meeting materials. |
| 740 | OPG | […]<br>The IESO should provide details on how marginal loss factors will be calculated in the hour preceding the dispatch hour. It is unclear whether they will be calculated and fixed as per pre-dispatch or whether there is separate process to calculate marginal losses. For market transparency and settlement reconciliation purposes, the results of the marginal loss factors should be published.<br><br>The IESO should also report on the differences between DA marginal losses and RT marginal losses to avoid marginal loss calculation differences from negatively impacting market participants who have financially binding DA schedules. | For real-time dispatch, the marginal loss factors for the dispatch hour will be determined in the pre-dispatch hour (PD-1) by the scheduling algorithm of the real-time calculation engine. This can be found in Section 3.7.2.3 of Real-Time Calculation Engine Detailed Design Document.<br><br>The marginal loss factors calculated by the engines for day-ahead, pre-dispatch and real-time can be obtained from the day-ahead, pre-dispatch and real-time LMP reports, respectively.<br><br>Note that the IESO will publish three components of LMPs, which can be used to calculate marginal loss factors for every resource. As per LMP formulation in Section 3.8.1.1 of the Real-Time Calculation Engine Detailed Design Document, the marginal loss factor for a resource is obtained by dividing the LMP loss component by the energy reference price. |

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| 741 | OPG | […]<br><br>The proposed settlement floor price of -$100/MWh for energy is inconsistent with -$20 settlement floor value that the IESO had proposed at the Negative Pricing stakeholder engagement session. If the IESO is imposing a settlement floor price of -$100/MWh, it should be appropriately stakeholdered with market participants. Please provide the rationale for this new amount and the reason for the change from -$20.<br><br>[…]<br><br>Without introducing a settlement floor market participants could be exposed to an inefficient and inappropriate settlement that could result in a significant financial impact. […]<br><br>[…]<br><br>The IESO should seek to quantify the benefits of the proposed change to the settlement floor and determine whether this change will require an additional mechanism to correct inefficient and inappropriate settlements. For example: Will this result in an additional make whole payment?<br><br>In summary OPG would like to discuss the quantum of the Settlement Floor to ensure there are limited inefficient market outcomes and inappropriate settlement amounts. | The IESO agrees that an appropriate settlement price floor is necessary to avoid creating potentially inefficient market prices. The IESO 's initial settlement price floor proposal was -$20/MWh. This proposal was discussed with stakeholders at the technical session held in February 2020. Details can be found in the meeting materials.<br><br>Stakeholder feedback at that session was that a settlement price floor of -$20/MWh could preclude otherwise efficient transactions from occurring; some intertie transactions and Ontario suppliers did have marginal costs that were lower than -20/MWh. No stakeholders expressed support for a settlement price floor of -$20/MWh.<br><br>With this feedback, the IESO re-assessed the proposal and changed the design to include a settlement price floor of -$100/MWh. The rationale for this change was provided at the August 2020 technical session. Details can be found in the meeting materials. |
| 742 | OPG | I section 2.2.3 the design states:<br>"Finally, the Publishing and Reporting Market Information process will produce a number of public, market participant confidential and internal IESO reports on the dispatch day resulting from the RT calculation engine. Refer to the Publishing and Reporting Market Information detailed design document for details."<br><br>OPG suggests that V1.0 of the Publishing and Reporting Detailed Design remains under review with many of IESO responses to stakeholder feedback including OPG's requests for additional details on reports and for the introduction of additional reports as:<br>"This request will be considered during the Implementation Phase."<br><br>A key concern for market participants is the enhanced need for market transparency: timely market results will enable market participants to adapt energy limited resource (ELR) optimization strategies to drive market and operational efficiencies as well as providing certainty to market participants of future dispatch schedules. | Thank you for the feedback. The IESO remains committed to providing market participants with the data needed to participate in the market. A number of new reports are being added to v2.0 of the Publishing and Reporting Market Information detailed design document. As mentioned, further details on reporting will be established in collaboration with market participants during the Implementation phase. |

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| 743 | OPG | Figure 2-2: Future RT Calculation Engine Process does not include RT constraints as proposed by OPG in Offers, Bids and Data Inputs detailed design comments. | RT will consider Hourly Must-Run, Min Daily Energy Limit and Forbidden Regions for hydroelectric resources.<br><br>For a response to the suggestions provided by OPG under Offers, Bids, and Data Inputs (OBDI) please see the response documents posted on October 19 2020 and December 2 2020. |
| 744 | OPG | [...] Please provide an example of how MIO will be performed and how it sets RT price. | Multi-Interval Optimization (MIO) will be performed in the same manner in the real-time calculation engine of the renewed market as it is performed in today's real-time constrained sequence. |
| 745 | OPG | [...]<br><br>Please provide an example of how the RT calculation engine evaluates the economics of a resource's offers to determine if the resource is to be shut down. | When the pre-dispatch calculation engine does not issue an operational commitment/extension to an Non-Quick Start (NQS) resource that is currently online, the real-time calculation engine will no longer be constrained to dispatch the resource to minimum loading point (MLP) or above. As today, the real-time calculation engine will then have the option to dispatch the resource below MLP, based on economic evaluation of the resource's offers. When this occurs, the resource will be dispatched on a shut-down trajectory. |
| 746 | OPG | On page 13, the design lists all items that are fixed for the hour… [this list] should also contain the minimum schedules for hydroelectric, such as, constraints required for linked resources on cascade river systems and resources with minimum hourly output (MHO) amounts as scheduled in PD-1. | Minimum Hourly Output and Cascade specific inputs will not be used as minimum and maximum constraints in the corresponding real-time hour. This reflects that the timing of spill restrictions varies for different hydroelectric resources and for different market participants. In today's market, spill restrictions are at times not imposed until much closer to or even during the dispatch hour. The future design must preserve the ability for dispatchable resources to maintain their dispatchable range until the market participant no longer expects that range to be dispatchable. If constraints were prematurely applied, it would preclude that resource and other market participant resources from being competitively evaluated to respond to changes in system conditions as the real-time hour approaches.<br><br>Any restrictions that need to be placed on specific resources can be managed using real-time actions (river/compliance aggregation, offers, de-rates and outages, safety, equipment, or applicable law) or by submitting Hourly Must-Run inputs where applicable. Please see the responses posted on December 2 2020 for OBDI items #136 and #142 for more details. |

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| 747 | OPG | In section 3.3 the design states:<br>"A pricing algorithm will calculate location marginal prices (LMPs). It will primarily use the same set of market participant inputs, IESO inputs and resource and system constraints as the scheduling algorithm. It will determine settlement-ready LMPs by performing a security-constrained economic dispatch allowing an offer or bid lamination to set price in accordance with the principle for price-setting eligibility."<br><br>Please provide details of any differences between price setting eligibility that occur due to the differences between Day Ahead (DA), Pre-dispatch (PD), and Real Time (RT) calculation engines. Examples or scenarios may be useful to illustrate the differences. | Each of the calculation engine detailed design documents contain specific sections that describe the constraints and pricing setting eligibility in the pricing algorithms.<br><br>DAM: Section 3.6.2.3, Section 3.6.9.2 and Section 3.8.2.3<br>PD: Section 3.6.2.3<br>RT: Section 3.6.2.3<br><br>In general, price setting eligibility does not change between the three calculation engines if the constraint is being evaluated in all three engines.<br><br>Further information on price setting eligibility, including any differences between the three timeframes, can be found in the pre-reading material for the technical session on August 27, 2020. |
| 748 | OPG | [...]<br>Please provide details on how the fixed marginal loss factors are calculated for a dispatch hour. | For RT dispatch, the marginal loss factors for the dispatch hour will be determined in the pre-dispatch hour (PD-1) by the scheduling algorithm of the RT calculation engine.<br><br>Section 3.7.2.3 of the Real-Time Calculation Engine detailed design document provides specific details regarding how marginal loss factors are determined. |
| 749 | OPG | In section 3.4.1.2 the design states:<br>"If more than one internal resource is connected to the IESO-controlled grid at the same electrical location, they will be considered to be at separate buses for the purposes of the optimization function."<br><br>Please provide an example to clarify how the IESO defines an internal resource, electrical location, and bus for the purpose of the optimization function.<br><br>If two non-variable generating resources connected at the same electrical location have equal energy offers, how is tie-breaking determined? | As today, an internal resource is any resource that is not importing energy into or exporting energy out of Ontario (i.e., not a boundary resource). Each resource will continue to be considered at a separate bus, regardless of electrical location, in order to ensure each is evaluated as an independent resource and receives its own energy and operating reserve schedules.<br><br>Consistent with today's methodology, tie-breaking will be determined by prorating based on the amount of energy offered and available at the corresponding price for each resource. This is described in Sections 3.4.1.5 and 3.6.1.2 of the Real-Time Calculation Engine detailed design document. |
| 750 | OPG | [...]<br>Please confirm the one ramp rate up and down is for simplification of the document and not representative of the calculation engine. If not, the IESO should provide justification for why multiple ramp rates are not accepted by the RT calculation engine for dispatchable loads. | As today, the real-time calculation engine will respect the submitted ramping profile consisting of up to five offered MW quantity, ramp up rate and ramp down rate value sets. |
| 751 | OPG | In section 3.4.1.3 p.19 the design states:<br>"$F10NXLSchi$, shall designate the fixed quantity of non-synchronized ten-minute operating reserve scheduled from the exporter..."<br><br>Does the above imply that the IESO will develop processes to allow exporters to offer operating reserve on interties? If so, could the IESO describe the processes that it intends to develop to coordinate with other jurisdictions? | This section is intended to describe the functionality of the calculation engine with respect to operating reserve on export transactions, and is not intended to imply that the IESO will develop processes to allow exporters to offer operating reserve on interties. Among other process changes, an agreement with a neighbouring jurisdiction would be required to enable exports to supply reserve to Ontario, and this is not part of Market Renewal. |

| ID | Stakeholder | Feedback | IESO Response |
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| 752 | OPG | The section Export Schedules on p.19 states that fixed export schedules:<br>"...may include emergency sales or inadvertent payback transactions."<br><br>The IESO should clarify its definition of fixed exports. There are other types of exports that could be considered "fixed" (e.g., Installed Capacity obligations to external jurisdictions), and OPG suggests changing the phrasing to "may include but are not limited to..." | The IESO will modify the language in this section in V2.0 of the Real-Time Calculation Engine detailed design document to enhance its clarity. |
| 753 | OPG | As per page 19 of the design:<br>"In circumstances when a dispatchable load without an active bid is observed through telemetry to be withdrawing energy from the IESO-controlled grid, the optimization function will assign a fixed schedule to this resource as determined by telemetry. This treatment will support the ability of a dispatchable load to designate its entire consumption as nondispatchable by not submitting an active bid."<br><br>Please identify any difference in settlement for dispatchable loads that do not have an active bid. | Dispatchable loads that do not have an active bid will be settled as described in Section 3.6 of the Market Settlement detailed design document. |
| 754 | OPG | In section 3.4.1.4 the design states:<br>"Supply inputs can belong to one of the following categories: …<br>• Schedules for generation without an active offer currently injecting into the IESO-controlled grid, known as no-offer generation; …"<br><br>Please provide clarification on what is considered no-offer generation and how this type of generation is assessed for compliance and settled. | There will be no change to what the IESO considers to be no-offer generation. It will continue to be assessed according to the current Market Rules. No-offer generation will be settled as described in Market Settlement section 3.6 |
| 755 | OPG | In section 3.4.1.4 the design states:<br>"The observed output of a self-scheduling generation facility as measured by telemetry will be used to determine a fixed schedule across the MIO look-ahead period in respect of the offer quantity provided by the facility, where: $FNDGi,b$ shall designate the fixed schedule for the non-dispatchable generation resource at bus $b \in BNDG$ for interval $i \in I$."<br><br>Please confirm that the fixed schedule above is independent of the offered schedule submitted and is solely dependent on metered values. | The IESO can confirm that the fixed schedule is solely dependent on operational telemetry values for the current dispatch hour. |

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| 756 | OPG | In section 3.4.1.4 the design states:<br>"The RT calculation engine evaluates the additional dispatch data submitted differently than the DAM and PD calculation engines because the RT calculation engine considers a rolling 60-minute look-ahead period."<br><br>Please provide examples of how intertie schedules, Minimum Hourly Output (MHO), Hourly Must Run (HMR), hydroelectric linked resources, min DEL constraints, etc. are transferred from the PD Calculation Engine to the RT Calculation Engine. OPG notes how this works will impact the MIO look-ahead period which will impact resource dispatches. | There will be no change to how intertie schedules are provided from the pre-dispatch to the real-time calculation engine.<br><br>When binding in pre-dispatch, Hourly Must Run and Min Daily Energy Limit quantities will be provided to the real-time calculation engine as minimum generation constraints for the dispatch hour. |
| 757 | OPG | [...]<br><br>Please provide an example of how the variable production forecasts used in MIO are integrated with variable generation offers, variable curtailments, and dispatches to other generation types. | There will be no change to how the variable production forecasts are used by the Real-Time calculation engine. |
| 758 | OPG | [...]<br><br>Please clarify whether a resource can be scheduled or dispatched within the lower and upper bound of the forbidden range. If this is a possibility, an example should be provided to illustrate when this may happen. | Like today, a resource may receive a dispatch within its forbidden region in real-time. This can only occur if the resource is being ramped out of its forbidden region at its maximum offered ramp rate. Resources will only receive a dispatch within the forbidden region if they are ramp limited such that a dispatch outside of the forbidden region cannot be achieved, given the offered ramp rates, within a single interval.<br><br>For example:<br>A resource with a maximum ramp rate of 5 MW/Min is currently dispatched and generating at 50 MW.<br>The resource has a forbidden region of 52-80 MW.<br>The RT calculation engine determines the most optimal dispatch schedule to be at 85 MW.<br>The resource will receive a dispatch of 77 MW on the next dispatch interval, to achieve its output of 85 MW (the target for the following dispatch interval). |
| 759 | OPG | On page 24 the design states:<br>"In circumstances when a generation resource without an active offer is observed through telemetry to be injecting into the IESO-controlled grid, the RT calculation engine will schedule this resource as required by the IESO to enable system reliability."<br><br>Please provide an example that explains the scheduling performed by the RT calculation and in what situations this would occur. | There will be no change to how the real-time calculation engine utilizes telemetry to account for output from a generation resource without an active offer. |

| ID | Stakeholder | Feedback | IESO Response |
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| 760 | OPG | [...]<br><br>Please define what the IESO considers adjustments for emergency purchases that do not support a sale. The IESO should also provide an example of adjustments for emergency purchases that do not support a sale that persist in real time impact price since they are not scheduled in the pricing algorithm. | Emergency purchases that do not support a sale refer to emergency imports into Ontario. These emergency imports will not be reflected as supply in the pricing step. This treatment helps market prices reflect the scarcity of supply that necessitated the emergency import. |
| 761 | OPG | The RT engine design identifies the hydroelectric parameters that will be respected in the RT calculation engine as: Forbidden Regions, Min DEL, and Hourly Must Run. IESO has identified that for Min DEL, the real time engine will accept minimum constraints from the pre-dispatch calculation engine to avoid situations where the resource may continue to be dispatched below its pre-dispatch schedules forcing the resource to meet the entire min DEL requirement at the end of the dispatch day. OPG recommends the real time engine must also include the minimum constraints from the PD calculation engine for the minimum hourly output, maximum number of starts per day and linked resources, time lag and MWh ratio parameters to avoid hydroelectric resources from entering into a SEAL condition in RT.<br><br>OPG included a similar comment in its review submission for the Grid and Market Operations Detailed design, as well as two additional comments with additional information and recommendations. These two supporting comments are reproduced below in the next two comments. | Minimum Hourly Output and Cascade specific inputs will not be used as minimum and maximum constraints in the corresponding real-time hour. This reflects that the timing of spill restrictions varies for different hydroelectric resources and for different market participants. In today's market, spill restrictions are at times not imposed until much closer to or even during the dispatch hour. The future design must preserve the ability for dispatchable resources to maintain their dispatchable range until the market participant no longer expects that range to be dispatchable. If constraints were prematurely applied, it would preclude that resource and other market participant resources from being competitively evaluated to respond to changes in system conditions as the real-time hour approaches.<br><br>Any restrictions that need to be placed on specific resources can be managed using real-time actions (river/compliance aggregation, offers, de-rates and outages, safety equipment or applicable law) or by submitting Hourly Must-Run inputs where applicable. Please see the responses posted on December 2 2020 to OBDI items #136 and #142 for more details. |

| ID | Stakeholder | Feedback | IESO Response |
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| 762 | OPG | The design states that the minimum hourly output (MHO) parameter is to be used when spill conditions are expected to prevent the generating unit from responding to dispatch instructions between 0 MW and the MHO. The DAM and PD calculation engine will use this parameter when scheduling a resource but in RT, if market participants expect spill restrictions to persist in the actual dispatch hour, they can submit an hourly must run value or enter an outage slip in advance of the dispatch hour. If spill restrictions develop during the actual dispatch hour, market participants can request a minimum generation constraint or enter an outage for the remainder of the dispatch hour.<br><br>The design seems to imply that dispatchable hydroelectric generation facilities must be capable of responding to 5-minute dispatch instructions and can spill as a normal course of action. Hydroelectric operators may be able to make decisions about sluicegate operation on an hourly basis on select river systems but not every 5 minutes. Sluicegates were not designed to be dispatchable and should not be considered a tool to facilitate dispatch instructions on 5-minute intervals.<br><br>OPG suggests a minimum constraint to the MHO or a maximum constraint to 0 MW is entered into the RT calculation engine if the pre-dispatch calculation engine schedules a resource for a MW quantity greater than or equal to its MHO in the PD-2 evaluation. This will reduce the number of outage slips entered and phone calls required in RT. Refer to OPG Comment #10 from Offers, Bids and Data Input Detailed Design. | Minimum Hourly Output and Cascade specific inputs will not be used as minimum and maximum constraints in the corresponding real-time hour. This reflects that the timing of spill restrictions varies for different hydroelectric resources and for different market participants. In today's market, spill restrictions are at times not imposed until much closer to or even during the dispatch hour. The future design must preserve the ability for dispatchable resources to maintain their dispatchable range until the market participant no longer expects that range to be dispatchable. If constraints were prematurely applied, it would preclude that resource and other market participant resources from being competitively evaluated to respond to changes in system conditions as the real-time hour approaches.<br><br>Any restrictions that need to be placed on specific resources can be managed using real-time actions (river/compliance aggregation, offers, de-rates and outages, safety equipment or applicable law) or by submitting Hourly Must-Run inputs where applicable. Please see the responses posted on December 2 2020 to OBDI items #136 and #142 for more details. |
| 763 | OPG | […]<br>The linked resources, time lag and MWh ratio parameters are parameters used to manage the intertemporal dependencies of cascade hydroelectric facilities. If linked resources are not considered in real-time, there is an increased risk of having an "unbalanced" river system and market participants will be required to request IESO to constrain units on or force generation out to manage real time operating constraints that will cause market inefficiencies.<br><br>OPG proposes logic that will transfer pre-dispatch schedules to real-time calculation engine in the form of minimum constraints to maintain balance on a cascading river system. When considering which pre-dispatch schedule was appropriate, OPG considered that the greatest flexibility would be able to be provided to the market by making the latest decision possible while weighing the need to break a link in PD-1 due to local inflow changes, outages, or other SEAL events. It is proposed that the IESO implement logic, transferring a minimum constraint equivalent to the PD-2 schedule to the real-time calculation engine for the upstream station of the cascade, with corresponding minimum constraints implemented based on the PD-2 schedule of the upstream station to the linked downstream stations. The downstream equivalents should receive minimum constraint schedules in real-time unless the links are broken/removed by the participant. Refer to OPG Comment #16 from Offers, Bids and Data Input Detailed Design. | Constraints for Linked Resources, Time Lag and MWh Ratio will not be used as minimum and maximum constraints in the corresponding real-time hour. This reflects that the timing of spill restrictions varies for different hydroelectric resources and for different market participants. In today's market, spill restrictions are at times not imposed until much closer to or even during the dispatch hour. The future design must preserve the ability for dispatchable resources to maintain their dispatchable range until the market participant no longer expects that range to be dispatchable. If constraints were prematurely applied, it would preclude that resource and other market participant resources from being competitively evaluated to respond to changes in system conditions as the real-time hour approaches.<br><br>Please see RT Calculation Engine item #746 and OBDI item #142 (posted December 2 2020) for more detailed responses. |

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| 764 | OPG | [...]<br><br>OPG acknowledges the IESO has made a prudent decision to fix the marginal loss factors for each interval in a given dispatch hour at the same value. However, market participants should have the ability to view these marginal loss factors before the close of the mandatory window. Without the ability to revise offers based on marginal loss factors dispatches may not align with market participants' intentions, which could lead to violation of SEAL restrictions. | As noted under ID#740, the marginal loss factors calculated by the engines for day-ahead, pre-dispatch and real-time can be obtained from the day-ahead, pre-dispatch and real-time LMP reports, respectively.<br><br>In order to address dispatch volatility concern, the real-time calculation engine will fix the marginal loss factors for the dispatch hour. In order to attain dispatch efficiency from utilizing dynamic loss factors, it will calculate the fixed marginal loss factors as close to the dispatch hour as possible. Therefore, the fixed marginal loss factors for the dispatch hour will be determined in the pre-dispatch hour (PD-1) by the scheduling algorithm of the real-time calculation engine.<br><br>As outlined in responses to feedback on the OBDI document, the submission and revision requirements for many of the data inputs related to SEAL restrictions will be revised. |
| 765 | OPG | [...]<br>OPG recommends transparent reporting of regional operating reserve minimum and maximum restrictions as these IESO inputs impact OR scheduling, pricing, and potentially market power mitigation actions by the RT Calculation Engine. | The IESO currently issues a Real-Time Area Reserve Constraints Report, which will continue to be published under Market Renewal. For more information please refer to the Publishing and Reporting Market Information detailed design document, Table 3-14, report 5. |
| 766 | OPG | [...]<br><br>The IESO should publish confidential reports as far in advance as possible for any resources with reliability constraints. OPG notes that resources with reliability constraints are subject to a stringent assessment of conduct and impact testing and if mitigated this result is required for reconciliation of settlements. | As outlined in GMOI feedback response ID#344, the IESO will provide information on reliability constraints during the day-ahead, pre-dispatch, and real-time timeframes. The IESO will provide information on reliability constraints in market participant settlement statements or settlement data files to allow for reconciliation of settlement amounts. |
| 767 | OPG | [...]<br>1. Please clarify how the minimum AGC limit will be applied to a station that has many resources providing AGC and a shared minimum AGC limit.<br>2. Please clarify the price setting eligibility of an AGC resource. Please provide an example which illustrates the settlement of an AGC resource with a 50 MW Day Ahead Schedule which was reduced to 40 MW in RT. DA $50, RT $40.<br>3. Please provide an example which illustrates the settlement of an AGC resource with a 50 MW Day Ahead Schedule which was increased to 60 MW in RT. DA $50, RT $40. | Like today, the RT calculation engine will account for AGC obligations through the setting of resource specific min and max limits that reflect how the market participant intends to provide AGC on its resources. In the new market a resource will be eligible to set price between these limits.<br><br>Regular two-settlement will apply to all resources providing AGC. The contract for providing AGC will be settled outside of two-settlement and does not impact two-settlement. |

| ID | Stakeholder | Feedback | IESO Response |
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| 768 | OPG | [...]<br><br>The IESO should publish the regional OR minimum and maximum requirements, as well as the set of buses able to satisfy or are limited by the requirements. | The IESO currently issues Real-Time Area Reserve Constraints Report which will continue to be published under MRP. Please see Publishing and Reporting Market Information detail design document Table 3-14 report 5.<br><br>This information will assist market participants in understanding the internal operating reserve constraints in real-time. The IESO will not publish information at the bus level. Publishing results at the bus level may provide opportunities for inappropriate conduct, such as exercise of market power. The IESO encourages all market participants to offer their resources based on their short-run marginal cost (including opportunity costs) to promote competition and overall market efficiency. |
| 769 | OPG | [...]<br><br>Please provide examples that demonstrate how the constraint violation penalty curves differ between the scheduling and pricing runs. | Materials prepared in advance of the November 2019 technical session on constraint violation pricing contains information describing how constraint violation penalty curves can differ between the scheduling and pricing steps of the relevant calculation engine. Details can be found in the meeting materials. |
| 770 | OPG | [...]<br><br>Please clarify which real time telemetry the IESO will use to determine initial conditions (i.e., revenue metering, operational metering, or another source). Will the initial conditions be determined net of station service loads? | Like today, resource initial conditions will be based on operational metering at the resource's injection point.<br><br>Depending on if the station service if being taken off the generation service transformer or from the station service transformer, the initial condition may or may not include station service load. |
| 771 | OPG | The IESO should provide details on how the tie-breaking modifiers for each variable generator will be determined (i.e. the TMBb value). Will the values be the same in the day ahead and real-time markets and how often will they change (e.g. monthly, daily, hourly)? | Like today, tie-breaking modifiers for variable generation resources will be determined via the daily dispatch order. The IESO currently randomly determines this daily dispatch order for variable generators that are registered market participants, and regularly updates and publishes such daily dispatch order in accordance with the applicable market manual. There will be no change to the process on how tie-breaking modifier values are determined in the future market. |
| 772 | OPG | Please provide an example of how the calculation engine would determine schedules when there are two or more equivalent offers for energy or operating reserve. [...]<br><br>[...] how would the schedules for each generator change if one of the units (e.g., Generator A) had a forbidden zone where it would have "normally" been scheduled in the absence of the forbidden zone? | Tie breaking in the renewed market will use the same rules that are implemented in the constrained sequence of the current market. This extends to the treatment of a resource with a forbidden region. That logic is described in Appendix 7.5 of the Market Rules, Section 2.8 - Tie-Breaking. |

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| 773 | OPG | The constraint equations to prevent hydroelectric resources from being scheduled within a forbidden region (p. 45) only appear to include terms for scheduled energy. IESO should consider the need for an additional constraint that prevents scheduled energy plus scheduled OR from landing in a forbidden region. If the combined DA schedules for energy and OR fall within a forbidden region, then subsequent OR activation may be infeasible. In the current market, the IESO sends ORAs within a forbidden region which may cause market participants to generate above the ORA to ensure the activation is deemed successful. The IESO should address this existing deficiency in market design. | As today, in the event an operating reserve activation occurs in real-time, the real-time calculation engine will respect the submitted forbidden region of the resource. Following the activation, the resource will be dispatched up to a MW quantity that respects the upper limit of the forbidden region. |
| 774 | OPG | [...]<br><br>Please provide additional information on how a non-negative schedule will be applied to energy storage resources, specifically, the load portion of the continuous offer curve which would likely require a negative schedule. | As today, the real-time calculation engine will only determine non-negative schedules for storage resources when they are offering to supply energy.<br><br>There will be no change to how energy storage resources receive schedules when consuming.<br><br>MRP is aware of the proposed changes identified by the Energy Storage Design Project (ESDP) interim design and will incorporate the changes into the draft MRP market rules and market manuals once the ESDP interim design rules are live. |
| 775 | OPG | On page 40 the design states:<br>“The maximum output of a dispatchable variable generation resource will additionally be limited by its forecast.”<br><br>Please clarify whether the forecast is hourly or on an interval basis. | As today, the demand forecasts utilized by the future RT calculation engine will be on an interval basis. |

| ID | Stakeholder | Feedback | IESO Response |
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| 776 | OPG | [...]<br><br>Please clarify how the RT calculation engine determines the capacity available for operating reserve. How does the engine ensure that energy limited resources (e.g. hydroelectric) have sufficient energy remaining for ORAs. It appears that the Energy + OR parameter proposed by OPG in previous review comment submissions has not been included in the design. | Total operating reserve (OR) scheduled on a resource is limited by:<br>• 30 minutes times the OR ramp rate<br>• Remaining capacity, which is maximum offered generation minus the energy scheduled<br>• Actual capacity of the resource, accounting for following constraints etc.<br>o Reliability constraints<br>o Regulation (i.e. no OR capacity when the dispatchable generator provides AGC service)<br>o Derate/outage<br>o NQS energy schedule (i.e. no OR capacity when the NQS energy schedule is less than MLP)<br><br>Total 10-min OR scheduled is also limited by:<br>• 10 minutes times the OR ramp rate<br>• 10-min reserve loading point<br><br>30-min OR scheduled is also limited by:<br>• 30-min reserve loading point<br><br>OR scheduled is also limited by:<br>• Maximum offered OR quantity<br><br>A constraint for Energy + OR will not be introduced as part of this design. Market participants with energy limits are expected to continue to manage the scheduling of operating reserve and energy in real-time via their offered quantities. For a more detailed response on this subject, please review OBDI feedback item #128 as posted on December 2 2020. |
| 780 | OPG | [...]<br><br>For market transparency and settlement reconciliation, the IESO should publish in confidential reports the outputs of Real Time Scheduling. | As today, the IESO will be issuing Real-Time Scheduling and Dispatch Reports, as outlined in Table 3-7 of Publishing and Reporting Market Information Detail Design. |
| 781 | OPG | [...]<br><br>Please confirm Real-Time pricing will use 1 x ramp rate not 3 x ramp rate. | The RT calculation engine pricing algorithm will use a 1x ramp rate. |
| 782 | OPG | This section includes brief description of price setting eligibility rules for forbidden regions but there is no mention of other hydroelectric parameters including: Minimum Hourly Output, Hourly Must Run, Linked Resources, or Minimum Daily Energy Limit. Please clarify how these parameters affect price setting eligibility in RT. | For all of these inputs, the MWs that are available to be dispatched to meet incremental demand - those that are not min or max constrained or fixed to a specific value - are eligible to set prices. |

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| 783 | OPG | [...]<br><br>Please provide details on which pre-dispatch hour run (i.e. PD-3) will be used to set the fixed marginal loss factor for RT and how the IESO intends to publish these fixed marginal loss amounts. Marginal loss factors will impact dispatch of resources and should be transparent to market participants. | The set of fixed marginal loss factors for the dispatch hour will be determined in the pre-dispatch hour (PD-1) by the scheduling algorithm of the real-time calculation engine.<br><br>As noted in the response to IDs#740, 748, 764, the marginal loss factors can be determined from the LMP reports. Market participants can use, for instance, pre-dispatch LMP reports to get marginal loss factors for every resource in a given hour. The IESO will publish three components of LMPs - reference price, congestion component and loss component - which can be used to calculate marginal loss factors at each location<br><br>As per LMP formulation in Section 3.8.1.1 of the Real-Time Calculation Engine Detailed Design Document, the marginal loss factor for a resource is obtained by dividing the LMP loss component by the energy reference price. |
| 784 | OPG | […]<br><br>For market transparency, the IESO should publish loss adjustments, sensitivity factors, and fixed marginal losses. The design mentions sensitivity factors are described in Section 3.7.2.3, but this does not appear to be the case. Please provide more details on sensitivity factors. | The marginal loss factors can be obtained from the published LMP and its components (reference price, loss component, congestion component). The market participants can use, for instance, pre-dispatch LMP reports to get the marginal loss factors for every resource in a given hour. As per LMP formulation in Section 3.8.1.1 of the Real-Time Calculation Engine detailed design document, the marginal loss factor for a resource is obtained by dividing the LMP loss component by the energy reference price.<br><br>As today, the IESO will not publish sensitivity factors. Publishing sensitivity factors may provide opportunities for inappropriate conduct, such as exercise of market power. The IESO encourages all market participants to offer their resources based on their short-run marginal cost (including opportunity costs) to promote competition and overall market efficiency.<br><br>The IESO will not publish loss adjustments. Like today, the loss adjustment value for each interval is obtained from the power flow solution and represents discrepancy between Ontario total system losses and linearized losses. The loss adjustments are not specific to any load or generation resource. The IESO will continue to report total loss in all three timeframes: Day-Ahead (report 7 in Table 3-5), pre-dispatch (report 5, Table 3-6) and real-time (report 11, Table 3-7), as noted in Publishing and Reporting Market Information detail design document.<br><br>Section 3.7.3 of the Real -Time Calculation Engine detailed design provided incorrect reference for sensitivity factors. The sensitivity factors are described in Sections 3.7.2.2 and 3.7.2.4. This will be corrected in version 2 of Real-Time Calculation Engine detail design document. |

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| 785 | OPG | [...]<br><br>Please provide an example that would allow market participants to model the potential impact on zonal price (both for non-dispatchable loads and virtual transactions). For market transparency, the load distribution pattern should be publicly reported. | The IESO will publish forecasted demand for the four demand forecast areas - Northwest, Northeast, Southwest and Southeast. The four demand forecast areas are described in Section 3.5.6 of Offers, Bids and Data Inputs Detailed Design v1.0. The IESO will not publish the load distribution factors. Publishing load distribution factors would result in providing confidential market participant specific demand information in a public report. |
| 787 | OPG | Please provide an example showing how intertie settlement prices (ISP), intertie congestion prices (ICP), and intertie border prices (IBP) are calculated when an intertie is import-congested in pre-dispatch. Please provide an example of this calculation both when the ISP is equal to the IBP and when the ISP is equal to the pre-dispatch intertie LMP. | The energy Intertie Border Price (IBP) is calculated and composed of the three components in the same way as an internal LMP. The IBP = Energy Reference Price + Energy Loss Component + Energy Congestion Component.<br><br>The Intertie Congestion Price (ICP) is the sum of the two shadow prices for the intertie limit constraint and the net interchange scheduling limit (NISL) constraint. Hence ICP = PExtCong + PNISL.<br><br>The Intertie Settlement Price (ISP) is the sum of the IBP and ICP.<br><br>For example, if the PD IBP was $20 and the intertie was import congested, the PD ICP would be negative and put downward pressure on the PD ISP to reflect the marginal cost of imports at that intertie. Let's assume the PD ICP was -$5, the PD ISP would then equal $15.<br><br>If NISL was also binding, the PD ICP could be increased or decreased depending on the net direction of scheduled transactions. For example if NISL was -$5, continuing the above example would result in a PD ISP of $10.<br><br>The RT ISP will be equal to the PD ISP, unless the RT IBP is below the PD ISP. That is, the RT ISP = Min (RT IBP, PD ISP). The effective RT ICP will be calculated by taking the difference between RT ISP and the RT IBP.<br><br>If the RT ICP does not equal the PD ICP, the two components of the ICP will be prorated based on their PD magnitudes so that their sum equals the effective RT ICP. |

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| 788 | OPG | Please provide an example of how the intertie and Net Interchange Scheduling Limit (NISL) subcomponents will be prorated based on their PD magnitudes if ICP in real time differs from the pre-dispatch ICP.<br><br>The NISL mechanism is flawed in today's market, which has resulted in the Market Surveillance Panel (MSP) making recommendation 2-1 in their May 2014-October 2014 Report. It stated:<br>"The Panel recommends that the IESO assess the methodology used to set the intertie zonal price for a congested intertie when the Net Interchange Scheduling Limit is binding or violated, in order to make the incentives provided by the intertie zonal price better fit the needs of the market"<br><br>Does the IESO expect the proposed calculation engine mechanisms to address the concerns raised by the MSP? | The intertie and NISL subcomponents are prorated similarly to the section detailing the price modification of intertie settlement prices. For example, if in PD the NISL component represented 60% of the intertie congestion, then in real-time for every dollar change in the LMP, NISL will move $0.60.<br><br>Yes, by having a NISL pricing component in the LMPs, the resulting price signals will encourage a market response that is consistent with system needs. |
| 789 | OPG | Please provide an example of how the ISP, ICP, and IBP are calculated when an intertie is export congested in pre-dispatch. | The energy Intertie Border Price (IBP) is calculated and composed of the three components in the same way as an internal LMP. The IBP = Energy Reference Price + Energy Loss Component + Energy Congestion Component.<br><br>The Intertie Congestion Price (ICP) is the sum of the two shadow prices for the intertie limit constraint and the net interchange scheduling limit (NISL) constraint. Hence ICP = PExtCong + PNISL.<br><br>The Intertie Settlement Price (ISP) is the sum of the IBP and ICP.<br><br>For example, if the PD IBP was $20 and the intertie was export congested, the PD ICP would be positive and put upward pressure on the PD ISP to reflect the marginal cost of exports on the intertie. Let's assume the PD ICP was $5, the PD ISP would then be equal to $25.<br><br>If NISL was also binding, the PD ICP could be increased or decreased depending on the net direction of scheduled transactions. For example, if NISL was $5, continuing the above example would result in a PD ISP of $30.<br><br>Like today, an intertie that is export congested will have a RT ISP equal to the sum of the RT IBP and the PD ICP. |
| 791 | OPG | The design uses the terms co-optimization and joint optimization. Please provide the definitions for these terms and whether they are interchangeable or have differing meanings. | The terms co-optimization and joint-optimization are synonymous. They refer to the determination of prices and schedules simultaneously for the energy and the three operating reserve markets. |
| 792 | OPG | Can the IESO provide details on the geographic layout of the Operating Reserve regions. Will they be the same as the new load zones? | The IESO will continue to provide an operating reserve regions report. As today, these regions differ from the IESO's 10 electrical zones. |

| ID | Stakeholder | Feedback | IESO Response |
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| 794 | OPG | The design states that the procedure for calculating LMPs for islanded nodes is as follows: […]<br><br>Please provide an example of how the engine will perform this procedure. Please specify how ties will be broken "arbitrarily" as described in step 3.<br><br>Lastly, if a region is not considered islanded in the Day Ahead timeframe, but becomes islanded in Real time, how are make-whole payments for resources in the islanded region affected? For example, if a resource with a Day Ahead commitment is unable to generate in real time due to islanding, will it be subject to balancing payments in real time? | For clarity, anytime an NQS resource is disconnected from the system, e.g. a unit breaker is in the open position or a transmission circuit connecting the resource is out-of-service, the calculation engine considers the resource to be an islanded node. The procedure provided enables the calculation engine to determine the LMP for an NQS resource that is disconnected from the system. The procedure achieves this by reconnecting the resource in the pricing step. This logic is not related to electrical islands nor administrative pricing for electrical islands.<br><br>In the procedure tie breaking is used in instances where the highest priority is equal between two or more reconnection paths that connects the resource to the system. The engine will select the reconnection path randomly (arbitrarily). The LMPs in these instances should be very similar regardless of the reconnection path.<br><br>This logic is not related to make-whole payment eligibility nor make wholes for electrical islands, and is used only to enable the calculation engine to calculate LMPs for disconnected NQS resources. |
| 795 | OPG | [...]<br><br>Reference levels may not reflect the offering intentions of market participants and could cause dispatches in real time that increase the likelihood of violating SEAL restrictions. To avoid this, market participants should have the ability to adjust offers in the mandatory window to maintain compliance with SEAL restrictions while respecting reference level thresholds. If the RT calculation engine strictly uses reference levels for resources that failed the conduct test, this could limit market participants' ability to reorient their offers.<br><br>Will the real time calculation engine have the ability to accept new offers in the mandatory window for resources that failed the impact test and whose offers were replaced with reference levels? | Resources with dispatch data parameters that fail both the conduct test and the price impact test in the pre-dispatch timeframe will be evaluated at the appropriate reference levels for those parameters in subsequent runs of pre-dispatch evaluations and in real-time.<br><br>Participants will be able to submit dispatch data values that are lower than the relevant reference levels prior to the close of the mandatory window. However, if a dispatch data parameter has failed the conduct and impact tests and been mitigated to its reference level, the calculation engines will not accept a value that is higher than the reference level. Doing so would allow the resource to exercise market power. |
| 796 | OPG | [...]<br><br>For market transparency and settlement reconciliation purposes the IESO should confidentially publish the economic operating point (EOP) for energy and the three types of OR. EOP impacts market participants DA Schedules, PD Schedules, RT Dispatches, assessment for make-whole payment mitigation, make-whole payments, etc… as such, this information is critical to market participants in all time frames. | The IESO will provide confidential reports to market participants regarding the economic operating point of individual resources. This information will be provided for all three timeframes (day-ahead, pre-dispatch and real-time). The mechanism for providing this information will be determined during implementation. |

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| 797 | OPG | In section 3.9.1 the design states:<br>"The following information from the RT calculation engine run will be required to generate data for the make-whole payment impact test:<br>. A list of resources that have reliability constraints applied as part of control actions, which were entered as an input to Pass 1;<br>. For each resource with such a reliability constraint, a list of 5-minute intervals over which the reliability constraint was applied; and<br>.A list of resources that submitted new offers during the real-time mandatory window, which were accepted by the IESO."<br><br>For market transparency and settlement reconciliation, the IESO should publish confidential reports with the information listed above. | The IESO will notify individual market participants when they have failed the make-whole payment impact test as part of the settlement mitigation process. Other information from the Real-Time Calculation Engine that is used as part of the settlement mitigation process may be provided as part of that confidential notice. Determining the solution to provide this information will be carried out during implementation.<br><br>The IESO will not publish the referenced data for resources that are not eligible for make whole payments or for make whole payments that have not been mitigated. Publishing this data when resources are not eligible for make whole payments or when make whole payments have not been mitigated may provide opportunities for inappropriate conduct, such as the exercise of market power. The IESO encourages all market participants to offer their resources based on their short-run marginal cost (including opportunity costs) to promote competition and overall market efficiency. |
| 798 | OPG | [...]<br><br>For market transparency and settlement reconciliation, the IESO should confidentially publish the enhanced mitigated conduct dispatch data set. | The IESO will notify individual market participants when they have failed the make-whole payment impact test as part of the settlement mitigation process. Information from the Enhanced Mitigated for Conduct (EMFC) data set may be provided as part of that confidential notice. Determining the solution to provide this information will be carried out during implementation.<br><br>The IESO will not publish EMFC dispatch data for resources that are not eligible for make whole payments or for make whole payments that have not been mitigated. Publishing EMFC dispatch data when resources are not eligible for make whole payments or when make whole payments have not been mitigated may provide opportunities for inappropriate conduct, such as the exercise of market power.  The IESO encourages all market participants to offer their resources based on their short-run marginal cost (including opportunity costs) to promote competition and overall market efficiency. |

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| 713 | Power Advisory | Inputs to Set Prices Require More Clarity, Should Best Reflect Shortage/Scarcity Conditions and Power System Supply Needs, and Examples are Needed<br><br>[…]<br><br>[…] more clarity is needed for these components:<br>• More details are required to inform market participants (MPs) and stakeholders on IESO's application of the constraint violation penalty curves, especially within RTM due to the need to ensure all system needs are met within real-time dispatch intervals to ensure power system reliability – in particular, clear numerical examples on how LMPs will be set when constraint violation penalty curves are applied, and when IESO can relax constraint violation penalty curves so as they will not set LMPs;<br>• […] IESO should implement shortage/scarcity pricing for energy and OR within MRP, and consider implementing an OR Demand Curve (ORDC) and/or some form of Extended LMP (ELMP) where certain variables are relaxed in respective calculation engines to permit non-convex costs (e.g., speed no-load) to be an input towards setting LMPs, and not be left to some subsequent phase post MRP implementation (as these market design features exist in wholesale markets across the U.S.); and,<br>• IESO inputs relating to OR requirements and securing additional OR, IESO adjustments to centralized forecasts for variable generator (VG) energy production, IESO adjustments to demand forecasts, IESO determination on reliability constraints, and IESO use of emergency control actions, all require more details and examples regarding how IESO interventions could impact generator and other resource scheduling and dispatch instructions, as well as setting LMPs. Process details are needed, particularly regarding how IESO makes decisions whether to adjust or activate these inputs. | 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.<br><br>The materials presented at the Constraint Violations stakeholder engagement meeting on November 25, 2019 describe the interrelationship of the operating reserve penalty curves and include supporting graphs and illustrations. The curve quantities and prices presented in the materials are used for illustrative purposes only. The actual values that will be used for the future market will be determined during the development of market rules and market manuals. |
| 714 | Power Advisory | Proposed Price Settlement Floor Requires More Analysis and Specific Stakeholder Engagement<br>[…] the Consortium continues to believe that negative pricing will impact IAM post implementation of MRP. We believe this will be the case relatively more so within some sub-zones within the Northeast and Northwest zones, due to projected demand/supply balance and supply mix comprised of many baseload and low marginal cost generation facilities.<br><br>[…] the Consortium recommends that IESO conduct further analysis on the potential impacts of implementing a -$100/MWh price settlement floor within MRP detailed design, and consult with MPs and stakeholders […]. | The IESO hosted a technical session on negative pricing and the proposed settlement floor, and received advice from stakeholders. Upon receiving that advice, the IESO re-reviewed the challenge, where fundamentally, these market outcomes of very low negative price occurring would be to the detriment of Ontario ratepayers, with no broad market benefit. The IESO looked at alternatives to this solution, including the potential to introduce an offer floor price for hydro. However, the complexities surrounding water management make creating an offer price floor a difficult task that could also have adverse effects on system reliability. Given these considerations the IESO decided instead to pursue the proposed concept. |