MRP Energy Detailed Design

Design Document: DAY-AHEAD MARKET CALCULATION ENGINE

Stakeholder Feedback Form

Date Submitted: *2020/09/30* **Feedback Due**: September 24, 2020	**Feedback provided by:** Company Name: Ontario Power Generation Contact Name: Greg Schabas Phone: [redacted] Email: [redacted]

The IESO is posting a series of detailed design documents which together comprise the detailed design of the MRP energy stream.

This design document is posted to the following engagement webpage: http://ieso.ca/en/Market-Renewal/Energy-Stream-Designs/Detailed-Design.

Stakeholder feedback for this design document is due on **September 24, 2020** to engagement@ieso.ca.

Please let us know if you have any questions.

IESO Engagement

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General feedback on the Detailed Design Document (please expand any section as required)
OPG's detailed review comments for the **IESO Market Day-Ahead (DA) Calculation Engine draft detailed level design** are provided in the tables below. OPG has submitted extensive comments on other key sections of the Detailed Design and has not yet received any written feedback from the IESO. Once received, the IESO's feedback on these comments may require OPG to revisit its review of the calculation engine design and provide additional review comments. OPG looks forward to working with the IESO to address/mitigate the issues we've identified so the final design can maximize market efficiency and minimize costs to customers. The following list provides a brief summary of the main themes in our comments and additional details on each is provided in the detailed comment table: a. The DA calculation engine equations are very detailed and complex. For market participants to gain a better understanding of their application the IESO should provide examples demonstrating their use including simple examples/scenarios illustrating solving of the objective function for scheduling and pricing for all three day ahead market (DAM) passes, including the resulting outputs. Other equations for which OPG would like examples are listed in detailed review comment #1 below. The IESO should also consider hosting webinars/workshops highlighting various DA calculation examples to provide better clarity to Market Participants. **Without these examples, OPG found it difficult to review the equations, apply them to scenarios or situations and provide adequate comments on the detailed design.** b. Without enhancements to joint-optimization of energy & operating reserve (OR), there is a high risk that hydroelectric resources will receive OR schedules in the DAM that they will not be able to physically achieve in real-time. OPG has previously proposed a new "Energy + OR Limit" market parameter to help address this concern. While this new parameter has not appeared in any design documentation to date, the IESO previously mentioned that other changes to the calculation engines may reduce or mitigate this concern. **However, it is not clear from our review how the issue is addressed and OPG requests additional details/explanation.** c. The IESO has incorporated both energy and OR into the maximum daily energy limit (DEL) and shared DEL (i.e. all unit at the station level) constraint equations without regard for how this will impact hydroelectric scheduling, price setting eligibility, and efficiency/competitiveness in the DAM. The IESO should remove OR from these max DEL constraint equations and seek an alternate solution that assesses constraints required for OR on an hourly basis, not daily. **This is a significant issue because it could negatively impact the competitiveness of hydroelectric in the DAM. Hydroelectric resources would be very limited in their ability to be scheduled for energy and OR in the DAM, which could force the IESO to procure energy and OR from less economic, carbon emitting sources such non-quick-start (NQS) gas.** d. The price setting eligibility for Energy Limited Resources (ELR) with a binding Max DEL requires a more market-based approach. The existing detailed design diminishes the value of ELRs when their fuel is scarce by binding the Max DEL on a total of energy and OR. This limitation will mute the price signals that create an efficient and competitive market. e. The DA engine design shows a -$100/MWh settlement floor price, which is inconsistent with the -$20 value that the IESO proposed at the Negative Pricing stakeholdering session. OPG is requesting rationale for the new settlement floor price of -$100/MWh, and suggests it should be appropriately stakeholdered with market participants. f. It appears that the Market Power Mitigation module of the DA calculation engine may be inconsistent with the principles and intent of the Market Power Mitigation Detailed Design Document. It is OPG's interpretation from the DA calculation engine design that the violation of one parameter under conduct testing would require impact testing on all parameters not just the one failing the conduct test. Please see detailed comments #36 & #37 for detailed explanations of the issues. g. There are many outputs from the DA calculation engine passes that should be published either publicly or privately depending on the confidentiality of the information to allow much needed market transparency and enable settlement reconciliation.

#	Section	Theme	Comment Name	Detailed Comment
1.	**General**	**IESO stakeholdering**	**Provide illustrative examples of solving of DAM equations**	The DAM calculation engine equations in the design are very detailed and complex. For market participants to gain a better understanding of their application the IESO should provide examples demonstrating their use. This should include simple examples/scenarios illustrating the solving of the following equations: • Solving of the objective functions for as-offered pricing and scheduling, reliability scheduling and commitment, and DAM pricing and scheduling, including the resulting outputs for all three DAM passes. • Examples of application of price-setting eligibility in as-offered and DAM pricing, including for DEL. • Calculation of locational marginal prices for energy and operating reserve. • Application of the energy limited resource constraint equations for max DEL and max shared DEL (on pages 67 & 68). The IESO should consider hosting webinars/workshops highlighting various DAM calculation examples to provide better clarity to Market Participants. **Without these examples, OPG found it difficult to review the equations, apply them to scenarios or situations and provide adequate comments on the detailed design.**
2.	**General**	**IESO stakeholdering**	**Add brief explanation of each DAM equation**	As a means of providing additional clarity the IESO should add a short (i.e. one or two sentence) explanation of the function and purpose for all the equations presented in the design.
3.	**General**	**DAM participation**	**Self-scheduling resource participation requirements in DAM**	OPG would like clarification on the requirements for self-scheduling resources to participate in the DAM. Section 3.3 of Offers, Bids & Data Inputs draft detailed design includes the following statement, which implies that self-scheduling resources need to participate in the DAM: *"Registered market participants* must submit *dispatch data* into the day-ahead market for the amount of energy they *reasonably expect* their *self-scheduling generation facility, intermittent generator* or *transitional scheduling generator* to provide in each *dispatch hour* of the *real-time market;"* However, Section 3.3.1. of the draft Grid & Market Operations Detailed Design states that self-scheduling resources are not subject to the ADE requirement and Section 4, Table 4-1 (page 122) includes the following statement: *"There is no requirement for dispatch data to be submitted into the day-ahead market in order for a self-scheduling generation facility, an intermittent generator, a transitional scheduling generator or a boundary entity to be eligible to participate in the real-time market."* The IESO should clarify the participation requirements for self-scheduling resources in the DAM and RTM. Are self-scheduling resources required to submit dispatch data in the DAM and if they do not, can they still participate in the real-time market?

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4.	**General Comment**	Hydro Parameters	**Proposal to enhance Joint Optimization of Energy and OR**	In OPG's review letter following the January 23, 2020 IESO stakeholder session on Physical Withholding, OPG provided a comment pertaining to the importance of joint optimization of energy and OR for hydroelectric facilities. OPG has reproduced the comment below and stresses that it is important for the IESO to consider this approach or an alternative that achieves the same outcome. Without enhancements to joint-optimization, there is a high risk that hydroelectric resources will receive OR schedules in the DAM that they will not be able to physically achieve in real-time. Without enhanced joint optimization of energy and OR, infeasible day-ahead OR schedules create inefficient market outcomes. For example: • Resource A receives a 100 MW infeasible day-ahead OR schedule in HE12 for $1 • Resource B offers 100 MW day-ahead OR @ $2 in HE12 – does not receive a schedule. • Resource A provides 0 MW real-time OR in HE12 – buyback of 100 MW at $3 • Resource B provides 100 MW real-time OR for HE12 at $3 reflecting higher opportunity cost in RT than DA. Resource A should not have been scheduled in the day-ahead market and forced to buy back in real-time as this creates an inefficient schedule/market. OPG noted in the July 8th, 2020 meeting between IESO and the Ontario Waterpower Association (OWA), the IESO alluded to changes to the calculation engines that may reduce or mitigate this concern. OPG appreciates the IESO has acknowledged the issue and is intending to identify the solution in the calculation engine detailed design. **However, it is not clear how the equations in the DA calculation engine design address this issue and the newly introduced Max DEL constraint equations <u>reduce</u> the efficiency, competitiveness, and transparency for hydroelectric resources in both energy and OR markets. The IESO should continue stakeholder discussions to address the significant challenges being created under the Market Renewal Program for hydroelectric.** ***"Comment #4: Proposal for new "Energy plus OR Limit" parameter to improve Joint-optimization of Energy and Operating Reserve*** *Energy and operating reserve (OR) have different market rules which impact how they are offered. For OR, a resource must be able to provide the energy activated by the operating reserve activation (ORA) for one hour. Along with the hydroelectric capability changes highlighted in Comment #1[1], hydroelectric resources also need to constantly evaluate whether they can provide OR for one hour. This uncertainty may lead to fluctuating OR quantities offered during different times of the day based on operating conditions.*

[1]Comment #1 from the OPG's review letter following the January 23, 2020 IESO stakeholder session on Physical Withholding was titled: "***<u>Comment #1:</u> Challenge with Establishing Physical Withholding Reference Levels for Hydroelectric Energy Offers".*** This comment is also reproduced including in OPG's review comments on the Market Power Mitigation Detailed Design (see Comment #9 from Market Power Mitigation comments).

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				For example, energy/OR offers early in the day may have to be reduced to ensure sufficient water remains available such that later energy/OR offers can remain above reference levels. If market participants are constrained in their offers in order to be physically compliant with the market rules, the result could be reduced system efficiency, higher OR prices, and higher overall cost to ratepayers. *To improve OR scheduling efficiency and reduce the risk of infeasible schedules, OPG proposes a new parameter term, "Energy + OR Limit", which specifies the maximum combined quantity of energy plus OR that can be sustained for one hour given water constraints. This new parameter would be particularly beneficial in the day ahead timeframe to reduce the likelihood of an infeasible schedule. An example of how this new parameter would affect joint optimization is shown in **Appendix A**."* The example is reproduced below in comment titled "Example of Proposed "Energy + OR Limit" Parameter (i.e. Appendix A). OPG is currently participating in stakeholder sessions with the IESO related to "Improving Accessibility of Operating Reserve". OPG has raised this proposed parameter with the IESO Stakeholder Engagement team, and they suggested the parameter be raised again through Market Renewal, as this additional tool change would be out of scope for their project. Through this stakeholder engagement the IESO has amended their ORA Performance Criteria to track actual dispatch rather than scheduled dispatch when issuing OR Activations (ORAs) in order for participants to meet their ORAs and be able to utilize their compliance deadband fully, this change would require changes to the DSO. OPG firmly believes this "Energy plus OR Limit" parameter should be addressed through Market Renewal or other active Market Initiatives, such as Expanding Participation in Operating Reserve and Energy (EPOR-E) or Improving Accessibility of OR.
a)	**General Comment**	Hydro Parameters	**Example of Proposed "Energy + OR Limit" Parameter (i.e. Appendix A)**	**The Issue**: The quantity a resource can achieve and sustain in an ORA is contingent on the current energy dispatch which fluctuates based on energy price and the actual output which may differ due to different reasons such as a compliance deadband. There is no parameter to limit the total amount dispatched for energy and scheduled for OR. **Example:** • Energy offer: 60 MW @$20, 70 MW @$40, 100 MW @ $100 • 10S OR offer: 10 MW @ $0.20, 70 MW@$100 (Note the 100 MW lamination is not offered) Only 10 MW of OR offered to coincide with energy dispatch of 60 MW based on Predispatch schedules – 70 MW is achievable for 1 hour. 100 MW is only achievable for 15 minutes. **Scenario 1: Pre-dispatch equals MCP at $25** • MCP $25 and OR Price $1

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				• Energy Dispatch: 60 MW • OR Schedule: 10 MW • ORA to 70 MW <u>Outcome:</u> Resource ramps to 70 MW in less than 10 minutes and remains at 70 MW for one hour. **<u>Scenario 2:</u>** Pre-dispatch Energy at $25. Market participant expects same outcome as Scenario 1 except MCP increases to $50 • MCP $50 and OR Price $1 • Energy Dispatch: 70 MW • OR Schedule: 10 MW • ORA to 80 MW <u>Outcome:</u> Resource ramps to 80 MW in less than 10 minutes. After 25 minutes the resource derates to 70 MW for water control. It FAILS the ORA since it was not able to provide one hour of OR. An example of the implementation of the proposed solution which reflects actual OR capability for 1 hour is outlined below: **<u>Example (as above):</u>** • Energy offer: 60 MW @$20, 70 MW @$40, 100 MW @$100 • 10S OR offer: 10 MW @ $0.20, 70 MW @$100 • Energy + OR limit: 70 MW **<u>Scenario 3:</u>** Scenario 2 with a new parameter "Energy + OR Limit" of 70 MW • MCP $50 and OR Price $1 • Energy Dispatch: 70 MW • OR Schedule: 0 MW <u>Outcome:</u> No ORA and no issue with non-compliance.
5.	**3.3.**	**Location Marginal Pricing (LMP)**	**Will LMP Nodes align with current location of resources on grid**	OPG would like confirmation that the nodes used for LMP in the new market will be at the same location on the grid as the resource locations in the current market.

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6.	**3.4.1.3**	**Hydro Parameters**	**Resolving conflicts between hydro parameters**	On page 32 just below Table 3-12 the design states: *"In circumstances where there is a conflict between the dispatch data parameter values submitted by a registered market participant for a hydroelectric facility, the engine would likely be unable to produce a solution. In such situations, the DAM calculation engine will be permitted to violate conflicting constraints created by the dispatch data submitted, as required."* If the DA engine needs to violate these constraints, the IESO should provide a set order in which the constraints will be softened/violated. For example, if Hourly Must Run and Minimum Hourly Output conflict, the engine should violate the Minimum Hourly Output and not the Hourly Must Run. The order of constraint violations should be similar in day ahead, pre-dispatch and real-time to enable the calculation engines to consistently model physical operating constraints that become safety, equipment limitations, and applicable law (SEAL) restrictions in real-time. This approach should allow the IESO to resolve potential conflicts well in advance of real-time. In OPG's comments provided for Offers Bids & Data Inputs Detailed Design, OPG identified limitations of the IESO detailed design which currently does not allow hydroelectric resources to use the hydroelectric parameters in the DAM, as the hydroelectric parameters are defined for SEAL constraints only. OPG recommended alternate wording to enable the use of hydroelectric parameters similar to how non quick start (NQS) units have physical operating constraints like minimum loading (MLP) and minimum generation block running time (MGBRT). OPG reiterates that hydroelectric stations have physical operating constraints in day ahead, but do not always have SEAL concerns until closer to real-time. Enabling the use of hydroelectric parameters to model physical operating constraints in day ahead and pre-dispatch will allow the parameters to aid in the creation of more feasible day-ahead and pre-dispatch schedules for hydroelectric and produce more efficient, competitive outcomes for market participants.
7.	**3.4.1.4 / 3.5.3**	**DAM inputs**	**Tie-breaking modifiers for variable generation**	The IESO should provide details on how the tie-breaking modifiers for each variable generator will be determined (i.e. the TMB_b 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)?
8.	**3.4.1.6**	**LMP**	**Use of dynamic loss factors for transmission losses**	As per previous comments submitted by OPG on the high level design, OPG remains concerned over the decision to adopt dynamic loss factors given the challenges that arose when they were first implemented at market opening in 2002. See OPG's previous comments on the Single Schedule Market high level design regarding dynamic loss factors reproduced below:

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				*"**2.3.2 Energy Price – Loss Component*** *"The IESO has also determined that dynamic loss factors will be used, where technically feasible, to more accurately calculate losses."* • *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). The IESO acknowledges these issues and states quasi-dynamic loss factors will be considered if using dynamic loss factors is not technically feasible.* ○ *Is the IESO suggesting possible different loss factor frequency updates by node?* ○ *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?* ○ *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."*
9.	**3.4.1.4**	**Notifications**	**Notification for DAM reliability must-Run and reactive support commitments**	How will notification of reliability must-run and reactive support obligations be communicated to market participants in the new market? In the current market, these instructions are provided in real-time. Will the IESO also be communicating these instructions day-ahead as well?
10	**3.4.2.2 / Appendix E**	**Market Power Mitigation**	**Conduct Thresholds**	Multiple sections of the design note that testing for economic withholding is not performed on energy offers below $25/MWh and physical withholding testing is not performed when the LMP is less than $25/MWh. A review of NYISO and MISO thresholds indicates they use $25USD/MWh. The IESO should convert this figure to Canadian dollars which is approximately $35 CAD/MWh. This would be appropriate as the IESO has indicated that many of these thresholds are based on US jurisdictional review. Further this value should be reviewed by the IESO on a periodic basis (e.g. every three years) to ensure it remains relevant for the Ontario market and reflects current gas prices, technology, etc.
11	**3.4.2**	**Additional Reporting Required**	**Constraint Area Designations**	In section 3.4.2.1, the design states: *"A list of NCAs and DCAs, along with facilities leading to the formation of, and resources located in, an NCA or a DCA, will be provided as inputs to the DAM calculation engine,"* For market transparency, the Constraint Area Designations used as DAM calculation inputs should be published in advance of the DAM submission window closing: this would allow market participants to react to upcoming market conditions.

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12	**3.4.2.2**	**Market Power Mitigation**	**Challenges with Setting Reference Levels for Hydroelectric**	Setting reference level prices for hydroelectric will be challenging given the relationship between opportunity costs, available water, and the configuration of the units at a resource. Physical offer quantities for hydroelectric resources also rely on available head/flows, which are dynamic in nature. Determination of these reference prices and quantities need to be thoroughly consulted and agreed upon with market participants. OPG would also like to highlight the risks associated with fuel supply (water) that a hydroelectric market participant has in the day-ahead timeframe and urges the IESO to factor risk premiums and dynamic opportunity costs into reference levels. (Note: changes to inflows also impact head based capacity of hydroelectric stations). Hydroelectric resources can be energy limited and offers are used to reflect the opportunity cost of water in what is expected to be the most valuable hours. If these offers fail the conduct and impact test, the ex-ante engine automatically overrides the market participant's offers with reference prices. This could result in a sub-optimal dispatch schedule as reference prices may not accurately represent the opportunity cost of the water, as these costs are dynamic and change hourly. This may also have operational implications on the market participant, leading to sub-optimal market outcomes and may invoke SEAL declarations.
13	**3.5.1**	**Alternative Reference Load Bus**	**Additional Reporting**	Section 3.5.1 of the design states: *"If the reference bus is out of service, then an alternative station will be chosen as per the prevailing system conditions."* When the reference bus is out of service, the IESO should publish the alternative station used as the reference bus. The location of the reference bus will impact congestion and loss components impacting market participants.
14	**3.6.1.2**	**Clarification/Examples Required**	**Violation Cost and Penalty Curves**	On page 54, the design states: *"ViolCosth calculates the total constraint violation cost and depends on the constraint violation variables."* It lists a large number of Violation Cost variables, which include penalty curves, transmission limits, import/export limits, etc… The IESO should provide an example of each of the violation cost variables listed on pages 54-56, with a focus on Operating Reserve Demand Curves (ORDC) which is a new concept under market renewal.
15	**3.6.1.4**	**Additional Reporting Required**	**Bid/Offer Constraints Applying to Single Hours**	For market transparency and settlement reconciliation purposes, the IESO should publish in confidential reports the bid/offer constraints applying to single hours.

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16	**3.6.1.4**	**Clarification/Examples Required**	**Inadvertent Payback**	On page 59 the design states: *“A constraint is required to schedule inadvertent payback transactions. For all hours* $h \in \{1,..,24\}$ *and all intertie zone sink buses corresponding to an inadvertent payback transaction* $d \in DXhINP$*:”* Please provide details of how inadvertent payback transactions are optimized within the DA Calculation Engine and publish the DA schedules for inadvertent transactions.
17	**3.6.1.5**	**Clarification/Examples Required**	**Multi Hour Constraints/Energy Ramping**	In section 3.6.1.5 on Energy Ramping the design states: *“In the following ramping constraints, a single ramp up rate and a single ramp down rate (* $URRDGb$ *and* $DRRDGb$ *for dispatchable generation resources,* $URRDLb$ *and* $DRRDLb$ *for dispatchable loads) are used. That is, the ramp rates are considered to be constant over the full operating range of the dispatchable generation resource or dispatchable load. However, the DAM calculation engine will respect the ramping restrictions determined by the (up to five) offered MW quantity, ramp up rate and ramp down rate value sets.”* Please provide an example of how the single ramp up and down rates interact with the DA calculation engine respecting up to five ramp up and down rates.
18	**3.6.1.5**	**Clarification/Examples Required / Additional Reporting**	**Multi Hour Constraints/Dispatchable Generation**	In section 3.6.1.5 on Dispatchable Generation the design states: *“Energy schedules for each dispatchable generation resource cannot vary by more than an hour’s ramping capability for that resource. The following three-part constraint handles ramping for a resource when it is committed. The constraint covers incremental change above the resource’s minimum loading point (MLP) in the hours where: the resource first reaches MLP (Start Up), the resource stays on at or above MLP (Continued On), and the last hour the resource is scheduled at or above MLP before being scheduled off (Shut Down). Only the “Continued On” constraint applies to quick-start resources because they are always committed.”* Please provide an example of how this constraint is applied to a non-quick start unit and for market transparency publish the constraints in confidential reports.
	3.6.1.5	**Clarification/Examples Required**	**NQS Across Midnight Constraints**	On page 66 the design for NQS states: *“At the beginning of the day, a resource’s previous day schedule is evaluated to determine any remaining minimum generation block run time constraints to enforce and determine the commitment … “* Please provide examples of how the constraints for Minimum Generation Block Running Time (MGBRT) and Minimum Loading Point (MLP) from the previous day schedule are applied and how this impacts settlement of DA Generator

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				Offer Guarantee and DA Make Whole Payments. The IESO should also clarify which schedule from the previous day is used for the initial input to the day ahead.
20	**3.6.3**	**Engine Capabilities**	**Impact of Market Power Mitigation (MPM) design on calculation engine run-time & capabilities**	OPG cautions the IESO to ensure the calculation engine's ability to perform mitigation testing does not negatively impact the ability to optimize day-ahead and pre-dispatch schedules in a timely fashion. The running time of the mitigation module should not cause the IESO to abandon hydroelectric optimization parameters or other market efficiencies. If this becomes the case, the IESO should re-assess the thresholds and re-open negotiations on reference levels.
	3.6.4	**Market Power Mitigation**	**Examples for MPM**	In section 3.6.4 the design states: *"In the conduct test, the dispatch data parameters submitted by market participants for their resources will be evaluated against reference levels. The conduct test checks whether financial dispatch data parameter values are within a set threshold level of the reference level. If a resource qualifies for more than one conduct test in either energy or operating reserve, the test with the most stringent threshold levels will be performed."* Please provide an example of how the conduct test is applied, for the case where a resource is selected for two conduct tests in both energy and operating reserve. It is unclear of how the most stringent thresholds will be applied. This example should explain how this impacts Reference Level Scheduling, Reference Level Pricing and the Market Power Mitigation Price Impact Test.
	3.10	**Pricing**	**Settlement Floor Price**	At the Negative Pricing Stakeholder technical discussion session in February, the pre-reading document 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, the DA Calculation Engine Detailed Design Document states: *"EngyPrcFlr shall designate the settlement floor price and be set equal to -$100/MWh;"* This is inconsistent with the -$20 settlement floor value that the IESO had proposed at the Negative Pricing stakeholdering session. If the IESO is imposing a settlement floor price of -$100/MWh, it should be appropriately

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				stakeholdered with market participants. Please provide the rationale for this new amount and the reason for the change from -$20. An appropriate settlement floor is necessary as highlighted by the IESO in the pre-reading material for the technical discussion on Negative Pricing, which states: *"Unlike the other options considered, the settlement floor permits hydroelectric facilities to continue to offer in a manner that allows them to manage the dispatch of their resources and thus to manage applicable water restrictions. The settlement floor will result in efficient price signals and appropriate settlement results. This would not necessarily be the case without such a floor.* *Without introducing a settlement floor market participants could be exposed to an inefficient and inappropriate settlement that could result in a significant financial impact. For example, assume a resource with positive marginal costs required 10 minutes to ramp from its current schedule of 100 MW down to 50 MW. If a transmission limit suddenly bound, the generator's LMP could (in the extreme) be -$2,000/MWh while it ramps down. Assuming a linear ramp down, the generator would have injected an average of 87.5 MW in the first interval and 62.5 MW in the second. As a result, the market participant would pay 150 MW x -$2,000/MWh / 12Int = -$25,000 during its two-interval ramp down."* In the IESO's scenario above using a settlement floor of -$20, the market participant would pay 150 MW *-$20/MWh/12 int = -$250 during its two interval ramp down. Whereas, the new settlement floor of -$100, results in a payment of -$1,250 for its two interval ramp down. The significance in the proposed change from -$20 to -$100 becomes even larger when reviewed in the context that the Negative Pricing pre-reading also states: *"However, in certain regions in Ontario, there are instances when locational prices[1] can be significantly less than $0/MWh. This has been most frequently observed in the Northwest of the province with negative prices occurring in roughly 10% of observed intervals between 2014 and 2016.[2]"* The IESO should seek to quantify the benefits of the proposed change to the settlement floor and determine whether this change will require an additional mechanism to correct inefficient and inappropriate settlements. For example: Will this result in an additional make whole payment? In summary OPG would like to discuss the quantum of the Settlement Floor in order to ensure there are limitedinefficient market outcomes and inappropriate settlement amounts.

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21	**3.6.1.4**	**DAM constraint equations**	**Hydro condensing unit not scheduled for 10S OR**	Per equation on Page 61 for determination of 10S OR schedule, the IESO should confirm whether a condensing or speed-no-load (SNL) quick-start unit is prevented from receiving a 10S schedule. For a quick start unit, $MinQDGb$ (minimum loading point) is zero while for a SNL/Condensing unit $SDGh,b,k$ is zero (no energy schedule), resulting in a zero 10S schedule per the equation reproduced below. If IESO confirms the current implementation prevents a SNL/Condensing quick start unit from receiving a 10S schedule, OPG encourages the IESO to resolve this condition. $\sum_{k\in K^{10S}_{h,b}} S10SDG_{h,b,k} \le \left(MinQDG_b \cdot ODG_{h,b} + \sum_{k\in K^{E}_{h,b}} SDG_{h,b,k}\right)\cdot\left(\frac{1}{RLP10S_{h,b}}\right)\cdot\left(min\left\{10\cdot ORRDG_b, \sum_{k\in K^{10S}_{h,b}} Q10SDG_{h,b,k}\right\}\right).$ **Example:** A hydro unit is on condense with ZERO MW output. MinQDG*b* = 0 MW (it is a hydro unit) ODG*h,b* = 0 (not scheduled) SDG*h,b,k* = 0 MW (not scheduled) RLP10S*h,b* = 0.1 (hydro OR min loading point) ORRDG*b* = 60 MW/min (ramp rate per minute) Q10SDG*h,b,k* = 70 MW (max OR can be provided) Right side = (0 *0 + 0) *(1/0.1) * (min{10*60, 70}) = 0 However, since the unit is on condense, the unit can provide at least 70 MW of 10S Operating reserve. An example of the application of the above equation for synchronized 10-minute operating reserve for a dispatchable generator would be beneficial to provide additional clarity.
22	**3.6.1.4**	**Hydroelectric Parameters**	**Constraint to prevent OR activation into a forbidden region**	The constraint equations to prevent hydroelectric resources from being scheduled within a forbidden region (at the bottom of page 63 and top of page 64) only appear to include terms for scheduled energy. IESO should consider the need for an additional constraint that prevents scheduled energy plus scheduled OR from landing in a forbidden region. If the combined DA schedules for energy and OR fall within a forbidden regions, then subsequent OR activation may be infeasible. In the current market, the IESO sends ORAs within a forbidden region which may cause

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				market participants to generate above the ORA to ensure the activation is deemed successful. The IESO should remedy this existing deficiency in market design.
23	**3.6.1.5**	**Hydroelectric Parameters**	**Hydroelectric vs. Energy Limited Resource**	On page 67 the design states: *"Energy-limited resources cannot be scheduled to provide more energy than they have indicated they are capable of providing. In addition to limiting energy schedules over the course of the day to the energy limit specified for a resource, the corresponding constraints ensure that energy-limited resources cannot be scheduled to provide energy in amounts that would preclude them from providing operating reserve when activated."* The IESO should provide an example for a hydroelectric station with the following attributes: Min DEL = 400 MWh Max DEL = 500 MWh Hourly Energy Capacity = 100 MW Hourly Operating Reserve Capacity = 80 MW The example should aim to answer the following questions, for current market and future market: 1. How many MWh of OR can be scheduled in a day? 2. How many MWh of Energy + OR can be scheduled in a day? OPG notes that in today's market, the ability to provide OR is assessed on an hourly basis and is independent of the DEL calculation. If OR is activated (ORA) then future energy for the day or next day would be reduced to meet any safety, equipment, or applicable law requirements at the station. The IESO should provide rationale including analysis about benefit to the market that is achieved by changing the calculation of DEL to include OR.
24	**3.6.1.5**	**DAM constraint equations**	**Maximum DEL Constraint should not include OR**	The IESO has incorporated both energy and OR into the maximum DEL and shared DEL constraint equations without regard for how this will impact hydroelectric scheduling, price setting eligibility, and efficiency/competitiveness in the DAM. The IESO should remove OR from these constraint equations and seek an alternate solution that assesses constraints required for OR on an hourly not daily basis. From the IESO Operating Reserve Guide: *"To offer operating reserve you must:* • *Be able to provide the energy within the time frame specified by the class of operating reserve involved (either 10 minutes or 30 minutes)* • *Be able to sustain supplying operating reserve energy for up to one hour - the neighbouring jurisdiction must allow this for import/export providers of reserve"*

#	Section	Theme	Comment Name	Detailed Comment
				In Section 4. Activation: *"Unlike normal energy or scheduled reserve dispatch instructions, activation can happen at any time. We activate reserve based on the energy offer price associated with the resource, not the operating reserve offer price"* Both of the above statements support the hourly scheduling of OR and the unscheduled nature of OR activations (ORA). The IESO should not assume for the purposes of DEL calculations that the fuel associated with providing OR is used on an hourly basis. This is an overly conservative approach since on most days, hydroelectric stations receive very few operating reserve activations. Anecdotally, two ORAs in one day at the same station is a very rare occurrence. One of the unintended consequences of limiting hydroelectric/ELR's ability to schedule OR would be that gas resources would be uneconomically picked up to fulfill the remaining OR requirement. The IESO should recognize that joint-optimization of energy and OR needs to be performed at the hourly level based on offer inputs by market participants which would consider quantities, offer prices, and an hourly limit to the combined schedule of energy and OR. This has been recommended to the IESO in previous comment submissions and stakeholder sessions and to date OPG has received no response from the IESO. The DEL constraints as written significantly reduce energy limited resources' ability to compete in the electricity markets and would increase costs to ratepayers. Hydroelectric resources would be very limited in their ability to be scheduled for energy and OR in the DAM, which could force the IESO to procure energy and OR from less economic, carbon emitting sources such NQS gas. OPG strongly urges the IESO to re-evaluate these constraints. $$\sum_{h=1..H}\left(\sum_{b\in B_s^{HE}}\left(ODG_{h,b}\cdot MinQDG_b+\sum_{k\in K_{h,b}^{E}} SDG_{h,b,k}\right)\right) + \sum_{b\in B_s^{HE}}\left(10ORConv\left(\sum_{k\in K_{H,b}^{10S}} S10SDG_{H,b,k}+\sum_{k\in K_{H,b}^{10N}} S10NDG_{H,b,k}\right) + 30ORConv\left(\sum_{k\in K_{H,b}^{30R}} S30RDG_{H,b,k}\right)\right)\leq MaxSDEL_s.$$

#	Section	Theme	Comment Name	Detailed Comment
25	**3.6.1.6**	**Clarification/Examples Required**	**Example Required - Loss Treatment of Interties**	Section 3.6.1.6 on page 70 the design states: *"Injections and withdrawals at each bus must be multiplied by one plus the marginal loss factor to reflect the losses or reduction in losses that result when injections or withdrawals occur at locations other than the reference bus. These loss-adjusted injections and withdrawals must then be equal to each other, after taking into account the adjustment for any discrepancy between total and marginal losses. Load or generation reduction associated with the demand constraint violation will be subtracted from the total load or generation to ensure that the DAM calculation engine will always produce a solution."* The IESO should provide an example to illustrate how this will impact transactions scheduled on the interties. Today's penalty losses published by the IESO for intertie export transactions for NY.ROSETON, MI.LUDINGTON, MD.CAVERTCLIFF can be less than 1.0 and lower than the penalty losses published for internal Ontario generation. OPG is concerned this is not an efficient and competitive approach that should be continued under MRP.
26	**3.6.1.6**	**Clarification/Examples Required**	**Examples Required - Constraint Violation Penalty Curves**	In section 3.6.1.6 the design states: "Sufficient *operating reserve* must be scheduled to meet system-wide requirements for synchronized *ten-minute operating reserve*, total *ten-minute operating reserve*, and *thirty-minute operating reserve* plus, when applicable, flexibility *operating reserve*. All applicable regional minimum requirements and maximum restrictions for *operating reserve* must also be respected. Constraint violation penalty curves will be used to impose a penalty cost for not meeting the *IESO*'s system-wide *operating reserve* requirements, not meeting a regional minimum requirement, or not adhering to a regional maximum restriction. The *IESO* will therefore meet its full *operating reserve* requirements unless the cost of doing so would be higher than the applicable penalty cost." The IESO should provide more details on constraint violation penalty curves and provide more detail on how all applicable regional minimum and maximum requirements will be respected without the use of penalty curves. Please provide examples for: 1. Solving the system wide OR requirements 2. Solving regional OR requirements
27	**3.6.1.6**	**Clarification/Examples Required**	**Example Required - Intertie Limits/Net Intertie Scheduling Limit (NISL)**	On page 74, the design states: *"The IESO must ensure that the set of DAM schedules produced would not violate any security limits associated with interties between Ontario and intertie zones. In each hour, the net amount of energy scheduled to flow over each intertie and the amount of scheduled operating reserve that would be delivered across the intertie must be calculated. For each flow limit constraint, these energy and operating reserve quantities (if applicable) will be summed over all affected interties and the result will be compared to the limit associated with that constraint." … "Changes in the net*

#	Section	Theme	Comment Name	Detailed Comment
				energy schedule over all interties cannot exceed the limits set forth by the IESO for hour-to-hour changes in those schedules. The net import schedule is su*mmed over all interties for a given hour to obtain the net interchange schedule for the hour, and:* *It cannot exceed the net interchange schedule for the previous hour plus the maximum permitted hourly increase.* *It cannot be less than the net interchange schedule for the previous hour minus the maximum permitted hourly decrease.* *Violation variables are provided for both the up and down ramp limits to ensure that the DAM calculation engine will always find a solution."* Please provide an example of how NISL will solve in the day head. The NISL mechanism is flawed in today's market, which has resulted in the Market Surveillance Panel making recommendation 2-1 in their May 2014-October 2014 Report, it stated: *"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"*
28	**3.6.1.7/3.6.2**	**Additional Reporting**	**Additional Reporting - As-Offered Scheduling and Pricing Outputs**	In section 3.6.1.7, the design states: *"As-Offered Scheduling will produce schedules and unit commitment statuses for all resources."* Section 3.6.2 states, "*The LMPs and related shadow prices will also be used in the Constrained Area Conditions Test and, if necessary, the Price Impact Test*" The IESO should publish the results for both As-Offered Scheduling and Pricing, this will provide market transparency into market power mitigation actions and are required for settlement reconciliation.
29	**3.6.2.3**	**Commitment Status**	**Additional Reporting**	On page 80, the design states: *"**Commitment Status Variables*** *Commitment decisions are fixed to the commitment statuses of resources calculated in As-Offered Scheduling."* The IESO should publish confidential reports with the results of the commitment statuses of resources from the As-Offered Scheduling for market transparency and to allow for settlement reconciliation.
30	**3.6.2.3**	**Price Setting Eligibility**	**Max DEL binding**	In section 3.6.2.3 on page 80 the design states:

#	Section	Theme	Comment Name	Detailed Comment
				"For energy-limited resources with a maximum daily energy limit that was binding in As-Offered Scheduling, the schedules calculated in As-Offered Scheduling will determine the price-setting eligibility of the resource's energy and operating reserve offer laminations. In each hour, energy or operating reserve laminations up to the total amount of energy and operating reserve scheduled in As-Offered Scheduling will be eligible to set prices." Please provide examples to clarify when an ELR with binding DEL is eligible to set price. It is unclear how OR schedules impact Daily Energy Limit and why OR schedules would impact the ability to set price. OPG requests clarification of the following scenarios: 1. Hourly As-Offered Energy Schedule of 50 MW and OR schedule 10 MW, how is price set? 2. If later passes of the DAM result in 60 MW Energy and 0 MW OR, how is price set? 3. If later passes of the DAM result in 60 MW Energy and 10 MW OR, how is price set? 4. An example where the binding As-Offered Schedule is not at the economic operating point (EOP) of either energy or OR. How is price setting eligibility determined? 5. How does the price setting eligibility impact the calculation of price considering the joint optimization of energy and OR?
31	**3.6.2.3**	**DAM constraint equations / Price Setting Eligibility**	**Max DEL binding**	Please elaborate on the intent and mechanics of the following DEL equation: $\sum_{k \in K_{h,b}^{E}} SDG_{h,b,k} + \sum_{k \in K_{h,b}^{10S}} S10SDG_{h,b,k} + \sum_{k \in K_{h,b}^{10N}} S10NDG_{h,b,k} + \sum_{k \in K_{h,b}^{30R}} S30RDG_{h,b,k} \leq \sum_{k \in K_{h,b}^{E}} SDG_{h,b,k}^{AOS} + \sum_{k \in K_{h,b}^{10S}} S10SDG_{h,b,k}^{AOS} + \sum_{k \in K_{h,b}^{10N}} S10NDG_{h,b,k}^{AOS} + \sum_{k \in K_{h,b}^{30R}} S30RDG_{h,b,k}^{AOS}.$ Is this equation intended to examine all laminations of a single bus, or does it place a constraint on dispatchable generation scheduled at all ELR buses ($SDGh,b,k$) against the total across all ELR AND hydroelectric resources ($SDGh,b,kAOS$)?
32	**3.6.2.3**	**Clarification/Examples Required**	**Example Required - Min DEL Price Setting Eligibility**	On page 80 the design states, *"For hydroelectric resources with a minimum daily energy limit that was binding in As-Offered Scheduling, the energy schedules calculated in As-Offered Scheduling will be treated as fixed blocks"*

#	Section	Theme	Comment Name	Detailed Comment
				OPG suggests that this concept requires further review and consideration depending on whether the resource was scheduled at or above its economic operating point. If the resource was scheduled at or above its economic operating point, it should be eligible to set price regardless of a binding Min DEL at some point over the 24 hour day.
33	**3.6.2.4**	**Energy/OR optimization**	**"Energy + OR parameter" - Bid/Offer Constraints Applying to Single Hours**	This section on Bid/Offer Constraints Applying to Single Hours, seems to be an appropriate place to implement the OPG proposed "Energy + OR parameter". OPG seeks the opportunity to collaborate with IESO on an appropriate mechanism to joint optimize energy and OR.
34	**3.6.2.7**	**LMP**	**Difference between shadow prices and LMPs**	The IESO should provide additional explanations on how the locational marginal prices (LMPs) calculated in the new market will differ from the shadow prices calculated in today's market? An example of the difference between LMP and shadow prices would add context. A specific example using net interchange scheduling limit and potential for make whole payments is also suggested. For additional transparency, shadow prices should be published in Day Ahead, Pre-dispatch, and Real-time as this will aid decision making of market participants.
35	**3.6.2.7**	**Additional Reports Required**	**As-Offered Scheduling and Pricing Reports**	In Table 3-16: Shadow Price Outputs of As-Offered Pricing and Table 3-17: LMP Outputs of As-Offered Pricing contain output variables that should be published to market participants in either public or confidential reports based on the nature of the content.
36	**3.6.4.3**	**Market Power Mitigation**	**Consistency with MPM Design - Conduct Test Energy**	In section 3.6.4.3 the design states: *"Resources that qualify for testing for market power mitigation in the energy market will have the following dispatch data parameters evaluated:* *Energy offer, including offers up to and above MLP (only applicable if energy offer is greater than $CTEnMinOffer$),* *Start-up offer, and* *Speed no-load offer."* From the statement above, it appears the IESO plans to test all the dispatch data parameters (energy offer, start-up offer, and speed no-load offer) even though only one parameter qualified for testing. Please provide clarification of this approach, as it does not appear to be consistent with the MPM detailed design document.
37	**3.6.4.4**	**Market Power Mitigation**	**Consistency with MPM Design - Conduct Test OR**	In section 3.6.4.4 the design states: *"Resources that qualify for operating reserve market power mitigation will have the following parameters evaluated:* *Operating reserve offer (only applicable if it is greater than $CTORMinOffer$),* *Start-up offer,*

#	Section	Theme	Comment Name	Detailed Comment
				Speed no-load offer; and *Energy offers for the range of production up to MLP.* *As noted above, if a resource qualifies for more than one operating reserve conduct test, the test with the most stringent threshold levels will be performed."* From the statement above, it appears the IESO plans to test all the dispatch data parameters (energy offer, start-up offer, and speed no-load offer) even though only one parameter qualified for testing. Please provide clarification of this approach, as it does not appear to be consistent with the MPM detailed design document.
38	**3.6.5.3**	**Reference Level Scheduling**	**Additional Reporting**	In section 3.6.5.3 the design states: *"Reference Level Scheduling will produce schedules and unit commitment statuses for all resources."* An additional confidential report should be published by the IESO with Reference Level Scheduling schedules and commitment statuses for all resources, this will benefit market transparency and settlement reconciliation processes.
39	**3.6.6.3**	**Additional Reporting**	**Additional Reporting - Reference Level Pricing**	The design lists variables/outputs from the Reference Level Pricing processes in Table 3-20: Shadow Price Outputs of Reference Level Pricing and Table 3-21: LMP Outputs of Reference Level Pricing that should be published for both market transparency and settlement reconciliation purposes.
40	**3.6.7.5**	**Additional Reporting**	**Additional Reporting – Price Impact Test**	The design for section 3.6.7.5 states: *"The outputs of the price impact test will include:* *1. The set of resources that failed the price impact test in each hour* $h\in\{1,..,24\}$ *by condition type (i.e. resources included in the sets* $BIThNCA$, $BIThDCA$, $BIThBCA$, $BIThGMP$, $BIThORL$ *and* $BIThORG$*);* *2. The LMPs (energy and operating reserve) that failed the price impact test in each hour* $h\in\{1,..,24\}$ *for each resource at bus* b *(i.e. parameters included in the set* $LMPITh,b$*); and* *3. A revised set of offer data for resources that failed the price impact test with dispatch data parameters that failed the corresponding conduct test replaced with reference levels."* The IESO should provide the outputs listed above to market participants as confidential reports to inform market participants of mitigation events and to allow for settlement reconciliation. Please provide examples of the revised set of *offer* data that must be output by the price impact test. This process was hard to follow without illustrative examples.

#	Section	Theme	Comment Name	Detailed Comment
41	**3.6.10**	**Additional Reporting**	**Publication of Pass 1 Outputs**	In section 3.6.10 the design states: *"For each scheduling variable SXX, $SXX1$ shall designate the Pass 1 scheduling results. For example, $SDL_{h,b,j}1$ shall designate the schedule for lamination j of the dispatchable load bid at bus $b \in BDL$ in hour $h \in \{1,..,24\}$. As another example, $OHO_{h,b}1$ shall designate whether the hydroelectric resource at bus $b \in BHE$ was scheduled at or above $MinHO_{h,b}$ in hour $h \in \{1,..,24\}$. In particular, the unit commitment statuses and affiliated start-up decision for Pass 1 will be denoted…"* The IESO should publish the Pass 1 scheduling and pricing results for all variables listed in this section.
42	**3.7.1.1**	**Constraints Overview**	**Pass 2: Evaluation of ELR schedules - Removal of OR from Max DEL constraint calculation**	In section 3.7.1.1, the design states: *"For energy that was not scheduled in a given hour in Pass 1, the price evaluated reflects the difference between the offered price of the unscheduled energy and the price at the resource's location as determined from Pass 1. This approximates the value of scheduling additional energy in that hour and is used as a measure against the cost of committing additional resources. This method for unscheduled energy in a given hour will only be applied when the resource's maximum daily energy limit constraint is binding in Pass 1. If this constraint is not binding, unscheduled energy will be treated in the same way as other internal incrementally dispatchable energy."* OPG is recommending that the IESO remove OR from the max DEL constraint calculation. See previous comments with rationale.
43	**3.7.1.1**	**Clarification/Examples Required**	**Pass 2: Evaluation of ELR schedules**	On page 113, the section on Evaluation of ELR schedules requires examples for: 1. A situation where the max DEL is binding in Pass 1, how is the incremental price calculated? 2. A situation where the max DEL is not binding in Pass 1, how is the incremental price calculated? 3. A situation where the max DEL is binding in Pass 1, but is no longer binding in Pass 2.
44	**3.7.1.2**	**Clarification/Examples Required**	**Pass 2: Variables and Objective Function**	In section 3.7.1.2, the design states: *"Additionally, the following variables are added to capture the breaking of energy-limited resource laminations according to their Pass 1 scheduled and unscheduled quantities: $S1DG_{h,b,k}$ shall designate the amount of dispatchable generation scheduled at bus $b \in BLIM$ in hour $h \in \{1,..,24\}$ in association with lamination $k \in K_{h,b}E$ corresponding to the Pass 1 scheduled portion of the lamination; and $S2DG_{h,b,k}$ shall designate the amount of dispatchable generation scheduled at bus $b \in BLIM$ in hour $h \in \{1,..,24\}$ in association with lamination $k \in K_{h,b}E$ corresponding to the Pass 1 unscheduled portion of the lamination."*

#	Section	Theme	Comment Name	Detailed Comment
				Please provide examples that show how the IESO differentiates between the amount of dispatchable generation scheduled and unscheduled in Pass 1, which include both Energy and OR amounts for ELRs with binding and non-binding DEL.
45	**3.7.1.2**	**Clarification/Examples Required**	**Pass 2: Objective Function Defined**	In section 3.7.1.2, the design states: *"Thus, Reliability Scheduling will maximize the value of the following expression:* $\Sigma(ObjDLh - ObjHDRh + ObjXLh - ObjNDGh - ObjDGh - ObjIGh - TBh - ViolCosth)$*…"* followed by definitions of each term. Please provide a non-mathematically expressed definition of this expression and each of the terms. It is very difficult for market participants to review these equations completely without advance degrees in math.
46	**3.7.1.3**	**Clarification/Examples Required**	**Pass 2: Constraints Overview - Shared DEL**	In section 3.7.1.3 the design states: *"For energy-limited resources or hydroelectric resources with a shared maximum daily energy limit, the schedule for each offer lamination must be equal to the schedules corresponding to the Pass 1 scheduled and unscheduled portions. …The schedules for the Pass 1 scheduled and unscheduled portions of the lamination must respect the affiliated quantities."* Please clarify what is meant by the "affiliated quantities". Are the "affiliated quantities" at the resource level or at the shared daily energy limit level?
47	**3.7.1.4**	**DAM constraint equations**	**Variable Generation**	In section 3.7.1.4 under sub title Operating Reserve Scheduling, the design states: *"These constraints are the same as in As-Offered Scheduling except* $AdjMaxDGh,b$*, which is adjusted as indicated above."* Please explain how $AdjMaxDGh,b$, is considered an Operating Reserve constraint since it only appears to be revised due to variable generation changes.
48	**3.7.1.7**	**Additional Reporting**	**Additional Reporting - Pass 2 Results**	In section 3.7.1.7 Outputs, the design states: *"Reliability Scheduling will produce schedules and unit commitment statuses for all resources. The results of Reliability Scheduling will comprise the Pass 2 results." … "In particular, the unit commitment statuses and affiliated start-up decision determined in Reliability Scheduling will be denoted as follows:* *◻* $ODGh,b2 \in \{0,1\}$ *shall designate whether the dispatchable generation resource at bus* $b \in BDG$ *was scheduled at or above its minimum loading point in hour* $h \in \{1,..,24\}$*; and* *◻* $IDGh,b2 \in \{0,1\}$ *shall designate whether the dispatchable generation resource at bus* $b \in BDG$ *was scheduled to start (reach its minimum loading point) in hour* $h \in \{1,..,24\}$*."* The IESO should publish the results of Pass 2 for market transparency and settlement reconciliation purposes.

#	Section	Theme	Comment Name	Detailed Comment
49	**3.10.1.2**	**Intertie Pricing - NISL**	**Example Required**	On page 142, the design has equations describing how intertie prices are calculated in situations 1,2,3, and 4. Please provide detailed examples of how IBP, NISL, internal congestion, intertie congestion, losses, and settlement floors are calculated and interact with each other. Examples with intertie offer guarantees and day ahead make whole payments should also be provided.
50	**3.10.3**	**Electrical Island**	**Example for Pricing Required**	Section 3.10.3 provides a process for determining the price for resources within an electrical island. Please provide detailed examples that will illustrate the process for steps 1 to 8 and continue to describe how islanded resources are settled. The settlement example should include Day Ahead Settlement, RT balancing, Day Ahead Make Whole Payments, Real Time Make Whole Payments, Day Ahead Generator Offer Guarantees, Real Time Generator Offer Guarantees, etc…
51	**DES-28 Market Settlements Detailed Design (Section 3.5.4)**	**DA bid/offer data**	**Intermediate modifications to DAM bid and offer data**	The following comment was included in OPG's review submission on the Market Settlements detailed design. It is reproduced below given its importance to the design of the DA calculation engine: "In section 3.5.4 the design states: "*This also avoids the possibility that any intermediate modifications made to DAM bid or offer data within the DAM calculation engine for optimization purposes to be accidentally submitted to the settlement process.*" What intermediate modifications is the DA calculation engine performing on DAM bid or offer data? Will this intermediate modification be transparent to impacted market participants? "

<table>
<tr><th>#</th><th>Section</th><th>Theme</th><th>Comment Name</th><th>Detailed Comment</th></tr>
<tr><td>52</td><td>General</td><td>Example Calculation</td><td>Sample calculation involving DEL constraint</td><td>
For the following example, would the IESO indicate:

How much each resource is scheduled for each hour in the DAM and RTM (giving special consideration to DEL constraint)
The total cost to the market in both DAM and RTM

<table>
<tr><th colspan="4">Resource</th></tr>
<tr><td></td><td></td><td>Hydroelectric Gen A</td><td>Gas Gen B</td></tr>
<tr><td>Physical Characteristics</td><td></td><td></td><td></td></tr>
<tr><td>Maximum Capacity Rating</td><td>(MW)</td><td>200</td><td>200</td></tr>
<tr><td>Minimum Loading Point</td><td>(MW)</td><td>20</td><td>80</td></tr>
<tr><td>Daily Energy Limit</td><td>(MWh)</td><td>2,520</td><td>4,800</td></tr>
<tr><td>Day Ahead Offers</td><td></td><td></td><td></td></tr>
<tr><td>Energy Offer</td><td>($CDN/MWh)</td><td>9</td><td>18</td></tr>
<tr><td>10Min NonSpin Offer</td><td>($CDN/MWh)</td><td>3</td><td>4</td></tr>
<tr><td>Startup Cost</td><td>($CDN)</td><td>0</td><td>100,000</td></tr>
</table>
<table>
<tr><th colspan="4">Energy Market</th></tr>
<tr><td></td><td></td><td>Day Ahead</td><td>Real Time</td></tr>
<tr><td>Hourly Demand</td><td>(MW)</td><td>100</td><td>100</td></tr>
<tr><td>Hourly 10S OR Demand</td><td>(MW)</td><td>10</td><td>10</td></tr>
<tr><td>10S ORA</td><td>(MWh)</td><td>N/A</td><td>10</td></tr>
</table>
NOTES:

Assume both resources reside within the same constrained area
Assume demand does not vary hour to hour
Assume DA and RT offers are identical
Assume both resource's offer price is constant, with lamination sizes increasing incrementally by 20MW

</td></tr>
</table>