MRP Energy Detailed Design Design Document: Pre-Dispatch Calculation Engine

Stakeholder Feedback Form

Date Submitted:	**Feedback Provided By:**	
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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 **December 2, 2020** to engagement@ieso.ca.

Please let us know if you have any questions.

IESO Engagement engagement@ieso.ca

General feedback on the Detailed Design Document (please expand any section as required)

OPG has submitted comments on key sections of the Detailed Design and is now submitting preliminary review comments on the **Pre-dispatch (PD) Calculation Engine Design** Document. OPG looks forward to working with the IESO to address/mitigate the issues identified to ensure the final design will maximize market efficiency and minimize costs to customers. The following list provides a summary of the main themes in our comments and additional details on each are provided in the detailed comment table:

a) The PD 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, including the resulting outputs. Other equations for which OPG would like examples are listed in the detailed comments below. The IESO should also consider hosting webinars/workshops highlighting various 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) As stated in previous review comment submissions, the minimum schedules from the PD calculation engine for the following hydroelectric parameters should be transferred to the RT calculation engine to respect the safety, equipment, and applicable law (SEAL) constraints of hydroelectric resources in real-time: minimum hourly output, linked resources, time lag and MWh ratio.

c) The IESO has incorporated both energy and OR into the maximum daily energy limit (Max 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. 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. Otherwise, there will be a disconnect between PD and RT schedules creating an inefficient market outcome.

d) OPG recommends that the RT mandatory window timeframe be reduced 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 offers based on changing conditions (e.g. hydroelectric flow, forced outages etc.). In NYISO for example, the mandatory window is only 75 minutes.

e) There are many areas where additional reporting is needed to increase market transparency. One example is the need to confidentially publish the economic operating point (EOP) for energy and the three types of operating reserve (OR). EOP impacts market participants Day Ahead (DA) Schedules, Pre-dispatch (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. Although, PD EOP does not appear to impact settlement reconciliation, it remains an important market signal/indicator for a market participant to revise offers for a more efficient market outcome.

OPG had planned to include follow-up comments to the IESO's feedback on previous OPG design review comments in this submission in order to meet the December 2nd "Final Feedback Review – all draft design documents" deadline shown on the IESO's website. However as of December 1, 2020, the IESO had not posted any feedback to stakeholder comments for the Day-ahead (DA) and Real-time (RT) calculation engine design sections and only partial feedback for the Bids, Offer & Data Inputs, Grid & Market Operations Integration, Market Power Mitigation, Market Settlements sections. OPG is still planning to provide follow-up comments for these sections after all the IESO's feedback on previous sections is posted on the website since the IESO feedback on one section of the design may impact our follow-up responses for other sections.

Many critical design elements impacting the use of the hydroelectric parameters to enable feasible DA, PD, and RT schedules remain uncertain. Further clarification is also required on joint optimization of energy and operating reserve, as market participants are still waiting on IESO responses to recommendations on many design elements. For example, no feedback to date has been received on the proposed "Energy + OR" Limit parameter, which was submitted to the IESO in February 2020

#	Section	Comment Name	Detailed Comment
1.	General	Labelling of all equations in the detailed design	The IESO should add a unique label/ID for every equation in the detailed design including those presented in the calculation engine sections and Market Settlements. This will make it easier to refer to specific equations during the implementation phase.
2.	General	Propose Shortening of mandatory win dow timeframe	OPG included a comment proposing that the duration of the 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: *"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."*
3.	General	Opening Mandatory Window for Demand Changes	When IESO makes significant (e.g. ±100 MW) changes to zonal demand and variable generation forecasts inside the mandatory window, it may 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.
4.	General	Private Reporting of Economic Operating Point (EOP)	For market transparency, 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 EOP is an important market signal that should be published in the PD timeframe to allow market participants to proactively react to changing conditions and re-offer generations where appropriate. Without the publication of EOP, a market participant will be unable to understand why they are not economically scheduled in PD which reduces our ability to resolve any anticipated SEAL impacts of not receiving an expected schedule.
5.	General	PD LAP should start at 18:00	OPG has concerns with the timing of the first run of pre-dispatch. The initial planned run is scheduled for 20:00 and maintaining this time would not provide sufficient time for market participants to react to market signals prior to 00:00. In the current market, market clearing price (MCP) volatility is observed in HE1 and HE2 which may be worsened due to the later run of PD at 20:00. It is not likely that the introduction of a DA market which relies on both Primary Demand and Variable Generation forecasts will reduce the need for market participants to assess market signals and make decisions on how to offer generation in HE1 and HE2. Advancing to initial run to 18:00 instead of 20:00 would help to ameliorate this issue. Market participants will use PD market signals (i.e. pre-dispatch reports) to make decisions about how to operationalize DA schedules and react to changing market conditions such as changes to primary demand, wind generation forecasts, transmission outages, etc.

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			If pre-dispatch engine information is not published until 20:00, the ability to react to market signals and re-offer resources to the market for HE1 and HE2 is very limited which may cause inefficient market incomes due to the lack of optimization between Day 1 and Day 2 resourcing schedules. In absence of this optimization, increased price volatility and inefficient unit commitments may limit the benefit of market renewal.
6.	2.2.4	Transfer of PD Calculation Engine Constraints to RT	Section 2.2.4 of the design states: *"The PD calculation engine also runs independently from the RT calculation engine with the following exceptions:* *- Hydroelectric generation facility minimum daily energy limits when binding and hourly must-run amounts are carried over from the PD calculation engine to the RT calculation engine as minimum operational constraints;"* In addition, the PD constraints for the following hydroelectric parameters should be carried over to the RT calculation engine as well: minimum hourly output, linked resources, time lag and MWh ratio. The minimum schedules from the PD calculation engine for these parameters should be transferred to the RT calculation engine to respect operational constraints of hydroelectric resources in real-time. OPG included a similar comment in its review submissions for the Grid and Market Operations and RT Calculation Engine design, as well as two additional comments with additional information and recommendations. These two supporting comments are reproduced below.
7.	Grid & Market Operations Integration , Section 3.7.2.2	Comment #43 from Grid & Market Operations Integration Review: Hydro spill cannot be assumed to be dispatchable	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. 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. 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.

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8.	Grid & Market Operations Integration, Section 3.7.2.2	Comment #44 from Grid & Market Operations Integration Review: Linked resource, time lag and MW ratio parameter needs to transfer to RT	The IESO design states the following in Section 3.7.2.2 of Grid & Market Operations Integration: *"Upstream and downstream resources can be dispatched for energy quantities that vary from their DAM and PD schedules. Dispatch instructions in the real-time market provide an opportunity for upstream and downstream resources to respond to intra-hour prices signals as long as those dispatch instructions fall within the dispatchable range of the generation units."* 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. 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.
9.	2.2.3.2	Use of Peak Demand Forecast in PD engine	The design states on Page 11: *"The PD calculation engine will use a demand forecast of the forecast hourly peak demand for any hour where there is a significant difference between forecast peak demand and forecast average demand quantity."* An example would better help with understanding the concept. What constitutes a "significant difference"?
10.	2.2.4	PD Calculation Engine Integration with the DA and RT Calculation Engines	Page 11 of the design states: *"The dispatch look-ahead DAM scheduled quantities for import and export transactions will limit import and export schedules beyond the first two forecast hours of the pre-period. Capacity imports/exports and imports to meet reliability needs are not limited by their DAM scheduled quantities in all forecast hours of the look-ahead period."* Please clarify how the DAM scheduled quantities will "limit" import and export schedules beyond the first two forecast hours. Does the above paragraph mean that for hours beyond the first two forecast hours, the PD engine will not consider import/export schedules that are higher than the DAM schedule? If so, inefficient unit commitments may occur outside the first two forecast hours.

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			For example: • the DAM export schedule on an intertie is **200 MW** in HE12. • During HE7, a market participant submits **600 MW** of economic export bids on the intertie for HE12. How would the additional 400 MW of export bids be treated by the HE8 PD run (i.e. beyond the first two forecast hours)? How would unit commitments for HE12 be impacted?
11.	2.2.4	PD Calculation Engine Integration with the DA and RT Calculation Engines	Page 11 of the design states: *"The dispatch look-ahead DAM scheduled quantities for import and export transactions will limit import and export schedules beyond the first two forecast hours of the pre-period. Capacity imports/exports and imports to meet reliability needs are not limited by their DAM scheduled quantities in all forecast hours of the look-ahead period."* Please clarify whether the "DAM scheduled quantities" referred to in this section are the global DAM schedule on the intertie, a participant's total DAM schedule on the intertie, or the DAM schedule for a specific transaction? If a market participant submits economic bids via an additional transaction in PD, would the PD calculation engine consider those bids?
12.	3.4.1.4	Which daily dispatch parameters will be fixed in PD	The top of Page 31 of the design includes the following statement: *"Certain daily dispatch data parameters will be fixed to one value across the look-ahead period when the PD look-ahead period spans multiple dispatch days"* Please specify which parameters will be fixed in this manner and provide an example across multiple dispatch days.
13.	3.4.1.4	Variable Generation Forecast in RT	Page 32 of the design states: *"For each registered facility supplying variable generation, the IESO will continue to provide an hourly production forecast for all time-steps of the look-ahead period which will serve to limit the amount of energy that the variable generation resource may be scheduled to generate in each respective hour."* Please clarify how the PD results are transferred and impact the RT calculation engine? If PD forecast is too low, will the resources output be limited/constrained to the max value in PD?
14.	3.4.1.4	Hydroelectric parameters described in Table 3-8 should be consistent as NQS parameters	The descriptions for *MinHOt,b* and *MinDELq,b* in Table 3-8 states: *"shall designate the minimum hourly output, which is the amount of energy that the resource is required to produce in time-step $t \in TS$, if scheduled to operate, to prevent the resource from operating in a manner that would endanger the safety of any person, damage equipment, or violate any applicable law."* As per OPG's review comments on Offers, Bids and Data Inputs design section, MHO and MinDEL are also required to reflect operational constraints of hydroelectric stations similar to how Minimum Load Point (MLP) and Minimum Generation Block Run Time

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			(MGBRT) are used by Non-Quick Start Units. The IESO did not include responses to OPG's previous comments on this topic in its feedback on Offers, Bids and Data Inputs provided on October 19, 2020.
15.	3.4.1.4	Resolving conflicts between hydro parameters in PD Engine	On page 35 just below Table 3-10 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 PD calculation engine will be permitted to violate conflicting constraints created by the dispatch data submitted, as required."* If the PD engine needs to violate these constraints, the IESO should provide an 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.
16.	3.4.1.5	Operating Reserve (OR) Requirements	On Page 37 the design states: *"In addition, the IESO will define a number of regions within Ontario that will have their own regional operating reserve minimum requirements and maximum restrictions. Each region shall consist of a set of buses at which operating reserve scheduled may be used to satisfy the minimum requirement for that region and is limited by the maximum restriction for that region."* Please clarify whether OR located in one zone can supply OR to a different zone. Please provide additional information about the OR areas and commit to publishing the OR requirements in all timeframes.

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17.	3.4.1.5	Tie-breaking modifiers for variable generation in PD vs. DA	On page 45 the design states: *"$TBM_{t,b\in\{1,..,NumVG_t\}}$ shall designate the tie-breaking modifier for the variable generation resource at bus $b\in BVG$ for time-step $t\in TS$."* The tie-breaking is defined as an hourly input data for each time-step t. In the DAM calculation engine design, tie-breaking is defined as a daily input data (on page 41 of DAM Calculation Engine document): *"$TBM_{b\in\{1,..,NumVG\}}$ shall designate the tie-breaking modifier for the variable generation resource at bus $b\in BVG$."* Can the IESO 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 DAM and RTM and how often will they change (e.g. monthly, daily, hourly)? If the tie-breaking is an hourly input data, will the IESO continue publishing the tie-breaking data in the reports?
18.	3.4.1.5	Tie breaking Example for Dispatchable Generation	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. For example, how would the engine schedule dispatchable generators in the following scenario: Load = 45 MW Generator A: offered 50 MW Generator B: offered 14 MW Generator C: offered 26 MW Assume that the calculation engine deems each of these offers to be "equivalent", and therefore must use the tie-breaking methodology outlined in section 3.6.1.2. To extend the above example, 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?
19.	3.4.1.6	Number of Starts by Hydroelectric Units	Page 47 of the design states: *"Similarly, the number of starts for hydroelectric resources must respect the number of starts already incurred as determined by the actual operation of the resource, plus any anticipated starts in time-step 1 of the look-ahead period"* The above logic/methodology will need to be extensively tested during the IESO sandbox testing.

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20.	3.4.1.6	Cumulative Energy Production for Energy-Limited and Hydroelectric Resources	Page 47 of the design states: *"The actual energy produced up to the current hour in the current dispatch day, plus the energy scheduled in time-step 1 of the look-ahead period, will limit the schedule of an energy-limited resource for the remainder of the current dispatch day. This quantity will also offset the amount of energy that must be scheduled to satisfy a hydroelectric resource's minimum daily energy limit."* The above logic/methodology will need to be extensively tested during the IESO sandbox testing. The IESO should also consider that Min and Max DEL values may need to be resubmitting on an hourly basis to account for actual water used with a subsequent conversion to MWh of energy for both Min and Max DEL. The Max DEL submission may also be reduced if market conditions caused spill instead of generation.
21.	3.4.1.6	Past Hourly Production for Linked Hydroelectric Resources	Page 48 of the design states: *"For linked hydroelectric resources, the past hourly energy production of upstream resources will be used to schedule downstream resources for time-steps in the look-ahead period within the time lag. These past hourly production schedules will be equal to the output measured by telemetry less any production scheduled as part of an operating reserve activation."* This statement and the logic behind it will need to be re-assessed after the IESO responds to OPG recommendations around the treatment of cascade river systems as part of the feedback provided on Offers, Bids, & Data Inputs and Grid & Market Operations Integration detailed design documents.
22.	3.4.1.6	Operating Reserve Activation for Linked Resources	On Page 48 the design states: "*These past hourly production schedules will be equal to the output measured by telemetry less any production scheduled as part of an operating reserve activation*". Please explain why energy scheduled as part of an operating reserve activation (ORA) is subtracted from the output measured by telemetry. ORAs can be sustained for multiple intervals, and therefore have a material impact, especially for cascaded hydroelectric resources where ORAs affect forebay elevations at downstream stations. OPG is unsure why this explicitly excluding this output from the calculation engine. This treatment seems to contradict the inclusion of OR in the Max DEL constraint.
23.	3.4.1.7	Use of hourly dynamic loss factors	The Real Time Calculation Engine Detailed Design section 2.2 states: "Marginal loss factors for each dispatch hour will be calculated in the hour preceding the dispatch hour. These marginal loss factors will then be held fixed for each interval in that dispatch hour. The same set of fixed marginal loss factors will be used for calculating schedules and prices." The PD Calculation Engine design appeared to omit how these hourly marginal loss factors would be transferred to the RT Calculation Engine. Please clarify which run of PD will be used to calculate and fix the hourly marginal losses.

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			For market transparency and settlement reconciliation purposes, the results of the marginal loss factors should be published. 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.
24.	3.4.1.8	Adjustment of Offers After Ex-Ante Mitigation	Page 50 of the design states: *"In cases where a resource provides updated offers that are priced lower than the respective reference levels, the updated offers will be used for the current PD calculation engine run."* i. Will the IESO notify market participants immediately when an offer has been mitigated? Offers are used by market participants to manage operational constraints, and prompt notification by the IESO of any changes will be necessary to allow appropriate action. ii. When a resource is mitigated, updated offers that are "lower than the respective reference levels" will be accepted in the current PD run. Resources pass the ex-ante conduct test, however, if offers are lower than the reference level plus the appropriate threshold. Since the calculation engine accepts offers above the reference level but below the threshold, should not market participants who were mitigated be allowed to submit updated offers that are also above the reference level but below the threshold? iii. Will resources that were mitigated be able to submit updated offer prices within the mandatory window?
25.	3.5.1	Reference Bus Out of Service	Page 56 of the design states: *"If the reference bus is out of service, then an alternative station will be determined as per the prevailing system conditions."* Please explain the process for determining the alternative station that will become the reference bus if Richview TS is out of service.
26.	3.5.5	Changes in Lead Time between Days	Page 57 of the design states: *"When the pre-dispatch look-ahead period spans two dispatch days (i.e., the 20:00 EST to 23:00 EST PD calculation engine runs of the current dispatch day) certain daily dispatch data parameters will be evaluated across the entire look-ahead period using the daily dispatch data submitted for the second day. The daily dispatch data parameters that will be evaluated in this manner include:* *…* • *Lead time…"* This may lead to under-utilization of NQS resources whose lead time increases from day to day. For example, a resource has a lead time of 2 hours in day 1, and a lead time of 4 hours in day two. The resource could technically synchronize between 20:00 EST and 23:00 EST on day 1. Given the language in section 3.5.5, however, the PD Calculation engine would not commit the resource, since only the 4-hour lead time parameter from day 2 would be considered. OPG recommends the IESO allows intra-day updates to daily dispatch data to mitigate this issue.

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27.	3.6.1.3	Constraints Overview	The constraints overview section is comprehensive; however, it lacks any comparison of the differences between how DA, PD, and RT calculation engines manage constraints. For market transparency and certainty, it would be beneficial for the IESO to provide market participants a table outlining the differences in treatments of constraints in each of the calculation engines.
28.	3.6.1.4	Inadvertent Payback	On page 69 the design states: *"A constraint is required to schedule inadvertent payback transactions. For all time-steps* $t \in TS$ *and all intertie zone sink buses corresponding to an inadvertent payback transaction* $d \in DXtINP$*"* Please provide details of how inadvertent payback transactions are optimized within the PD Calculation Engine and publish the PD schedules for inadvertent transactions.
29.	3.6.1.4	Constraint to prevent OR activation into a forbidden region	The constraint equations to prevent hydroelectric resources from being scheduled within a forbidden region (on page 75) 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 PD schedules for energy and OR fall within a forbidden region, then subsequent OR activation may be infeasible. In the current market, the IESO sends ORAs within a forbidden region which may cause market participants to generate above the ORA to ensure the activation is deemed successful. The IESO should remedy this existing deficiency in market design.
30.	3.6.1.5	Hydroelectric vs. Energy Limited Resource	On page 80 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."* In today's market, the ability to provide OR is assessed on an hourly basis and is independent of the DEL calculation. Hydroelectric operational constraints change hourly especially on cascade river systems where upstream/downstream discharges impact operating reserve availability.
31.	3.6.1.5	Maximum DEL Constraint should not include OR	The IESO has incorporated both energy and OR into the maximum DEL and shared DEL constraint equations (on Pages 82 and 83) without regard for how this will impact hydroelectric scheduling, price setting eligibility, and efficiency in PD. 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)*

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			• *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"* 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 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. 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 PD, which could force the IESO to unnecessarily commit less economic, carbon emitting sources such NQS gas in PD instead. OPG strongly urges the IESO to re-evaluate these constraints.
32.	3.6.1.5	Multi Hour Constraints/Energy Ramping	Page 76 of 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 PD 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 PD calculation engine respecting up to five ramp up and down rates.
33.	3.6.1.1	Example / Clarification Required - Intertie	On page 89, the design states: *"The IESO must make sure that the set of PD schedules produced will not violate any security limits associated with interties between Ontario and intertie zones. In each time-step, the net amount of energy scheduled to flow over each intertie and the amount of*

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		Limits/Net Intertie Scheduling Limit (NISL)	*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 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 summed over all interties for a given time-step to obtain the net interchange schedule for the time-step, and:* ▪ *It cannot exceed the net interchange schedule for theprevious time-step plus the maximum permitted hourly increase.* ▪ *It cannot be less than the net interchange schedule for the previous time-step minus the maximum permitted hourly decrease.* *Violation variables are provided for both the up and down ramp limits to ensure that the PD calculation engine will always find a solution.* Please provide an example of how Net Intertie Scheduling Limit (NISL) will solve in pre-dispatch. 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"* Also, what will the NISL be after Market Renewal? Will the current value of 700 MW remain in effect?

#	Section	Comment Name	Detailed Comment
34.	3.6.1.6	Security Assessment equation signs	At the bottom of Page 88 (IESO Internal Transmission Limits), the first equation is for pre-contingency: $$\sum_{b \in B^{NDG} \cup B^{DG}} PreConSF_{t,f,b} \cdot Inj_{t,b} - \sum_{b \in B^{DL} \cup B^{HDR}} PreConSF_{t,f,b} \cdot With_{t,b} + \sum_{d \in DI} PreConSF_{t,f,d} \cdot Inj_{t,d} - \sum_{d \in DX} PreConSF_{t,f,d} \cdot With_{t,d} - \sum_{i=1..N_{PreITLViol_{f,t}}} SPreITLViol_{f,t,i} \leq AdjNormMaxFlow_{t,f}.$$ The second equation is for post-contingency: $$\sum_{b \in B^{NDG} \cup B^{DG}} SF_{t,c,f,b} \cdot Inj_{t,b} - \sum_{b \in B^{DL} \cup B^{HDR}} SF_{t,c,f,b} \cdot With_{t,b} - \sum_{d \in DI} SF_{t,c,f,d} \cdot Inj_{t,d} - \sum_{d \in DX} SF_{t,c,f,d} \cdot With_{t,d} - \sum_{i=1..N_{ITLViol_{c,f,t}}} SITLViol_{t,c,f,i} \leq AdjEmMaxFlow_{t,c,f}.$$ Why are the signs before the energy generation item $Inj_{t,d}$ different between the two equations (i.e. a "+" in the pre-contingency equation and a "-" in the one for post-contingency)?
35.	3.6.3	Market Power Mitigation in PD	Page 108 of the design states: *"If a resource fails the price impact test, reference levels for the dispatch data parameters that failed the conduct test will be used in the* ***subsequent runs*** *of Pre-Dispatch Scheduling and Pre-Dispatch Pricing for that hour* ***through to the real-time*** *timeframe."* If the market condition is changed (e.g., the resource does not fail in Price Impact Test due to demand and LMP decrease, or early return service of the transmission line from the outage), is the failed resource re-assessed in the future PD runs or does the mitigated (reference level) offer remain in PD calculations?
36.	3.7.2.4	Post-contingency thermal limits in reports	The 2nd last paragraph of Page 130 in the Contingency Analysis section states: *"The calculated post-contingency MW flows will continue to be compared to the post-contingency branch thermal limits for all the monitored equipment. For each monitored equipment, up to a pre-defined configurable number of the most severe violations will be linearized and passed to the optimization function as a linear constraint."* The post-contingency thermal limits impact the congestion shadow price which is an important component of locational marginal price (LMP). Does IESO publish the post-contingency thermal limits in any public reports?