MRP Energy

Detailed Design Engagement

Hydroelectric Dispatch Data

Meeting Summary

Background

The IESO hosted a technical session on the Hydroelectric Dispatch Data section of the Energy detailed design within the Market Renewal Program (MRP) on November 14, 2019 in downtown Toronto (IESO Offices) from 9 a.m. to 2 p.m.

The focus of the discussion was the Hydroelectric Dispatch Data, specifically the design elements related to minimum hourly output, daily energy limits, maximum starts per day, forbidden regions, and intertemporal dependencies on a cascade river system. Required reading material on these design topics was shared two weeks in advance to support the discussion on November 14.

The purpose of the in-person session was to understand stakeholder questions and perspectives based on the reading material provided in advance to inform the release of the draft detailed design section. The design section when fully released will be open to additional engagement, feedback and discussion with stakeholders.

Attendance

The following organizations participated in the session:

- Association of Major Power Consumers of Ontario
- Bruce Power
- Ontario Energy Association
- Evolugen
- Ontario Power Generation
- Northland Power
- Power Advisory LLC
- Ministry of Energy, Northern Development and Mines
- TransAlta
- H20
- Ontario Waterpower Association

Discussion Topics:

Overall, the discussion with stakeholders focused around providing the IESO more dynamic data to enable optimal outcomes in the market. The following themes emerged from stakeholder questions and comments during the session:

- In general, stakeholders commented that they would like more information on how the new parameters will be treated in the optimization and if they set price.
  - The IESO is still working on these aspects of the design and will include it in the detailed design.

Minimum Hourly Output

- A stakeholder indicated that for sites where there is no ability to spill, the proposed design for Minimum Hourly Output (MHO) could result in day-ahead and pre-dispatch schedules of 0 MW that the market participant could only meet by violating safety, environmental and legal (SEAL) constraints. The participant suggested the IESO reconsider having MHO be non-dispatchable for a subset of resources with no ability to spill.
  - Stakeholders noted that only a subset of resources do not have spill capability, and that may only be for certain periods of the year.
  - Stakeholders discussed that there could be two types of MHO – a ‘hard’ MHO for SEAL constraints that cannot be resolved through spill and a ‘soft’ MHO for SEAL constraints that can be economically resolved by spill.
- Stakeholders discussed possibilities for how the optimization engine could identify and handle ‘tiebreaker’ scenarios where two dispatchable resources have offered at the price floor, but one has a ‘hard’ MHO.
  - A participant suggested having different price floors for different resource types.

Daily Energy Limits

- Stakeholders identified the need to update minimum daily energy limit values between day-ahead and real-time since these limits change as water management conditions change throughout the day.
- Stakeholders discussed opinions on make-whole payment eligibility for a few scenarios that consider the interplay between the MHO and minimum daily energy limit parameters.
  - Stakeholders expressed that if a resource was scheduled to generate in an hour to respect the minimum daily energy limit even though they offered above the market clearing price, they may not be eligible for a make-whole payment.
  - Stakeholders stated that make-whole eligibility for MHO respected schedules and minimum daily energy limit respected schedules may need to be treated differently. This

may be because with MHO schedules, the market participant is signaling that they must run in a specific hour, whereas with minimum daily energy limits the optimization engine is signaling the optimal time for the resource to run.

Maximum Starts per Day

- Stakeholders discussed the potential need for registering more than one threshold for the number of megawatts that is considered a start to accommodate for tests and multiple resources.
- Stakeholders also suggested that reports may need to be provided to market participants that indicate the hours in which the optimization engine counted a start.

Forbidden Regions

- Stakeholders supported the IESO's recommendation to eliminate the need to align offers with forbidden regions. Participants also supported exploring the opportunity to expand the number of regions, if feasible given the potential impact on the optimization engine's processing time.
- Stakeholders noted that forbidden regions can vary daily based on the head levels and gate positions of hydroelectric facilities. As a result, it was requested that forbidden region constraints for generation units be submitted as dispatch data, rather than registration data.

Intertemporal Dependencies on Cascade River Systems

- Stakeholders had questions about the optimization engine vendor and what solutions they have for modelling intertemporal dependencies on cascade river systems.
    - The procurement process for the vendor is still underway. The IESO is not aware of any vendors with an off-the-shelf solution for how to model cascade dependency constraints for a competitive market.
    - The IESO and stakeholders agreed that another session would be necessary to further define cascade dependency constraints and how those constraints could be translated into dispatch data that the optimization engines would respect.

<u>Next Steps:</u>

The feedback and discussion with stakeholders at these sessions is being used to inform the detailed design sections which will be released and subject to stakeholder comment and discussion in the upcoming few months.

<u>Feedback:</u>

Written feedback that was received (with permission to make public by the submitter) has been appended to this meeting summary.

OPG Questions for Hydroelectric Dispatch Data Meeting

1. Where the IESO used other jurisdictions for comparison:
    a. Which jurisdictions specifically were used and can the IESO share references that were used?
    b. How do these jurisdictions schedule OR?
    c. What percentage of their supply is hydroelectric?
2. For the MHO quantity, how would the IESO respect this parameter if the accompanying price is not economic?
3. Will must run parameter offers be price setting?
4. Will forbidden region parameters be in registration data or daily data?
5. OPG's understanding of the "multiple DEL" parameter when initially discussed in the HLD was that the parameter would recognize a finite amount of hydroelectric energy (MWh) per lamination price for multiple prices, which would prevent the scheduling engine from scheduling more water than available at a specific price lamination. The IESO's description of this parameter appears to have changed. Is the previous concept of "multiple DEL" still being pursued in addition to what is written in the document?
6. What methodology does the IESO propose to use to review and determine the "opportunity cost" to be included in the reference price if it is "dynamic and influenced by a participant's own view of financial risk" (page 5).

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Chris Codd
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November 26, 2019

Independent Electricity System Operator
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Toronto, ON M5H 1T1

Attention: Darren Matsugu, Senior Manager – Market Design and Integration

Dear Darren:

RE: Market Renewal Program – Detailed Design for Energy Stream Hydroelectric Dispatch TransAlta's Comments

Thank you for opportunity to participate in the IESO's session on the detailed design for hydroelectric dispatches. TransAlta appreciates the IESO's efforts to engage with stakeholders on these issues within the Market Renewal Program Detailed Design for the Energy Workstream. TransAlta is submitting these comments to highlight issues that were raised at the November 14th session and propose potential solutions to these issues for the IESO's consideration.

TransAlta is supportive of the IESO's proposals for hydroelectric dispatch but we are concerned with how dispatches are issued, and prices set under some situations. In situations where the calculation engine dispatches a resource to comply with physical constraints, there is a risk that the calculation engine will be optimizing in a way that does not reflect competitive outcomes. This is not a concern in situations where a market participant is required to manage its offers to respect its own operational constraints because the market participant has an incentive to act in a competitive manner. An example of why this is a concern is described below with respect to the Minimum Daily Energy Requirement (MDER). The same concern would exist for the cascading energy production.

Example: Minimum Daily Energy Requirement (MDER)

Based on the proposal outlined, the calculation engine could dispatch out-of-merit offers to respect the MDER. This raises concerns about how the calculation engine would seek to optimize the dispatch of the MDER energy. The calculation engine would seek to optimize based on how price is set in this situation.

More clarity is also needed about how price would be set when an out-of-merit offer is dispatched. There are at least three options to set price:

1. Price is set by the marginal dispatched out-of-merit offer.
2. Price is set by the marginal offer dispatched excluding the dispatched out-of-merit offer(s).
3. Price is set by the marginal offer including the offers displaced by the dispatched out-of- merit offer(s).

Option 1 has the potential to create inefficient price signals and raises competitive advantage concerns. Under Option 1, price would be set higher than outcomes ignoring the MDER. This could lead to suppliers seeking this price by offering lower to receive a dispatch. The hydroelectric owner also has the potential to increase its offers knowing that the calculation engine must comply with the MDER.

Option 2 has the potential to create uncompetitive outcomes. There is a risk that the calculation engine will dispatch the MDER energy to minimize costs to consumers since the MDER energy is effectively reducing demand when dispatched. This does not reflect a competitive outcome. A resource's owner would seek to maximize revenues while complying with the MDER.

Option 3 would encourage the optimization engine to appropriately consider competitive outcomes in the absence of the MDER but does not necessarily lead to a competitive outcome. If a small amount of energy needs to be dispatched to satisfy the MDER, Option 3 would reflect a market participant seeking to optimally offer just below the marginal offer to satisfy its MDER. If a large amount of energy needs to be dispatched, Option 3 would not reflect the offers that would be displaced.

The simplest solution is to require market participants to manage their own offers to respect the MDER. However, it may be possible to implement Option 2 but design the calculation engine to comply with a resource's MDER in a manner consistent with a profit-maximizing entity. This could be done by scheduling MDER energy to maximize revenues to the hydroelectric facility over the day-ahead and pre-dispatch periods. This would minimize distortions in the energy market and create more competitive outcomes.

The added complexity of this concept may create unintended consequences in the co-optimization of the energy and OR markets. We have not had enough time to work through an example to test this possibility. This may mean that Option 3 is a next-best solution that comes closest to reflecting a competitive outcome.

Please contact me if you have any questions about the foregoing. Yours truly,

TRANSALTA CORPORATION

Chris Codd

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Senior Regulatory Advisor

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December 6, 2019

IESO Stakeholder Engagement

Re: H2O Power Comments for Market Renewal Energy Workstream Detailed Design: Hydroelectric Dispatch Data

H2O Power has reviewed the Hydroelectric Dispatch Data detailed design materials which formed the basis for the discussion at the meeting held on November 14, 2019.

Based on our internal review and discussions with other hydroelectric operators, H2O Power has prepared the attached presentation package. I would welcome the opportunity to present this slide deck at the beginning of the February 6, 2020 Technical Session.

H2O Power sees hydroelectric facilities as highly valued and flexible system resources. Hydro facilities are uniquely challenged in Ontario unlike other electricity sources, given the regulatory environment in which they operate. In order to properly model hydroelectric facilities, and in particular cascaded hydro systems, it is imperative that all stakeholders have a strong understanding of the constraints in which hydroelectric facilities operate and the benefits, when properly managed, to the Ontario electricity system.

I would kindly ask for 30 minutes, including Q&A, at the beginning of the session to present the attached material. I believe that the presentation will help set the stage for the ensuing discussions that will take place during the day.

I would welcome any feedback on the presentation and would incorporate any suggestions into the final deck.

Please do not hesitate to contact me directly at either marc.mantha@h2opower.com or at (905) 438-8539 x3203.

Looking forward to hearing from you,

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Regards,

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Vice President, Operations
H2O Power Holding LP

Copy:
Stephen Somerville, H2O Power Holding LP
Paul Norris, Ontario Waterpower Association
Lynn Wizniak, OPG

Cascaded Hydro

February 6, 2020 presentation to IESO Stakeholder Engagement Technical Session

Issues for discussion

- Current state
- Hydro Myths
- Water Management Plan constraints & responsibilities vs “Market” responsibilities
- Cascaded facilities – single Owner/Operator
- Cascaded facilities – multiple Owners/Operators
- Using Hydro efficiently

Current state of affairs

- Hydro facilities have been in service for many years
  - Reliable operation over the years
  - Operators figured out how to move water and make electricity efficiently.
    - …then came de-regulation…
- “Water Management Plans” and “Market Operations” are relatively new concepts into the Ontario system
- Hydro operations occur on a large number of river systems each with their own unique challenges and characteristics
- Hydro operations are working…in spite of the Market and regulatory constraints.
  - Always room for improvement!
    - Energy efficient dispatch and coordination

Hydro myths…

- Hydro is not flexible”
  - Hydro is very flexible, within its regulatory constraints;
  - Quick start-up, shutdown and ramp times;
  - Can do baseload, intermediate, peaking;
  - Can be rescheduled, within reason

LRIA & Water Management Plans

- *Energy Competition Act* passed Oct 1998.
- *Lakes and Rivers Improvement Act* (LRIA) amended in 2000 to establish the statutory authority of the MNRF to order the preparation of a Water Management Plan (WMP) for operation of waterpower facilities.
  - Direct result of anticipated potential outcome of deregulated energy markets.
- End result is the revised description of operating plans for each facility & watershed that is **legally enforceable** under the *LRIA*.
- The intent of the WMP is to provide certainty and clarity as to how waterpower facilities and control structures are operated with respect to levels and flows, **so as to balance environmental, social and economic objectives**.
  - Note that "economics" are listed last in the priority of objectives

Water Management Plans

- Hydro Operators 1st objective is to manage water
- Electricity generation is secondary
  - Manage the water first, then figure out how & when to generate with the water available”.
- Hydro facilities are uniquely challenged in Ontario unlike other electricity sources:
  - LRIA & associated Regulations, including WMP’s, provide the regulatory framework for operation of hydro facilities;
  - “social license” provided by LRIA to operate dams overrides all other factors, **including production of electricity.**

Operator’s Market “responsiblities”

- Submit offers, factoring in:
  - Cost;
  - Equipment limitations;
  - Energy limitations;
- Respond to dispatch instructions
  - Follow schedule for intermittent facilities
- Operate facilities within their described capabilities while meeting all other regulations, laws, etc.

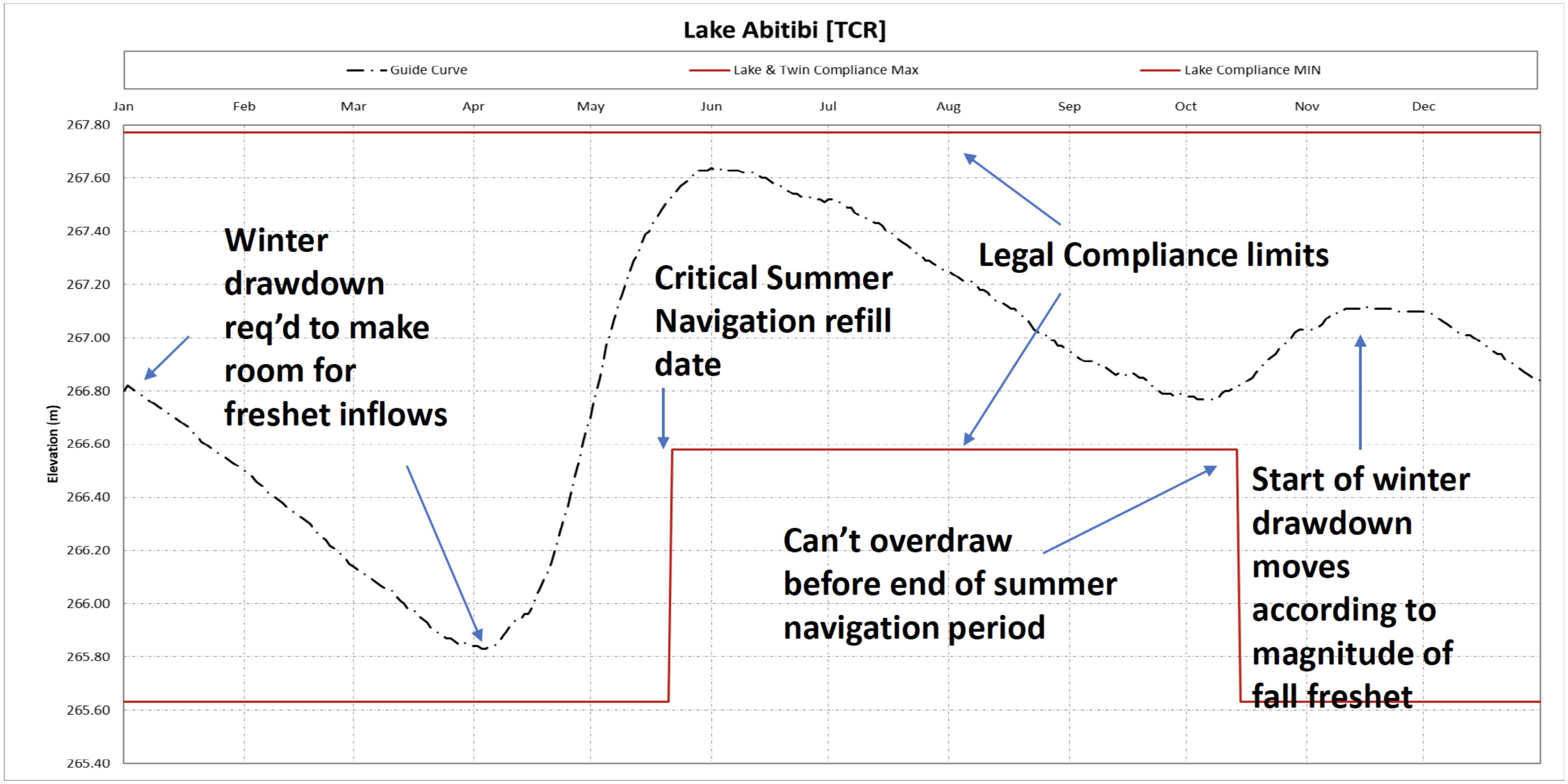
Plant operations issues in the "Market"

- Stop start cycles.
  - Maintenance costs (short term)
  - Equipment longevity (longer term)
- Operating at inefficient turbine settings
  - Vibration, cavitation
    - Cost curve for inefficient operation is inverted (higher all-in cost at lower opening)
  - Lower energy production per unit/water. (more water (cm/s)/MWHrs produced)
- Spillways are installed for the purpose of managing excess flows, not to manage electricity production schedules.
  - Hydro plants constrained off with inflows coming from upstream facilities >>> Spill!
  - Most sluice gates were not designed for continuous operation under winter conditions.
  - Spillway operation outside of freshet periods introduces an unintended Public Safety component

Reservoir Management

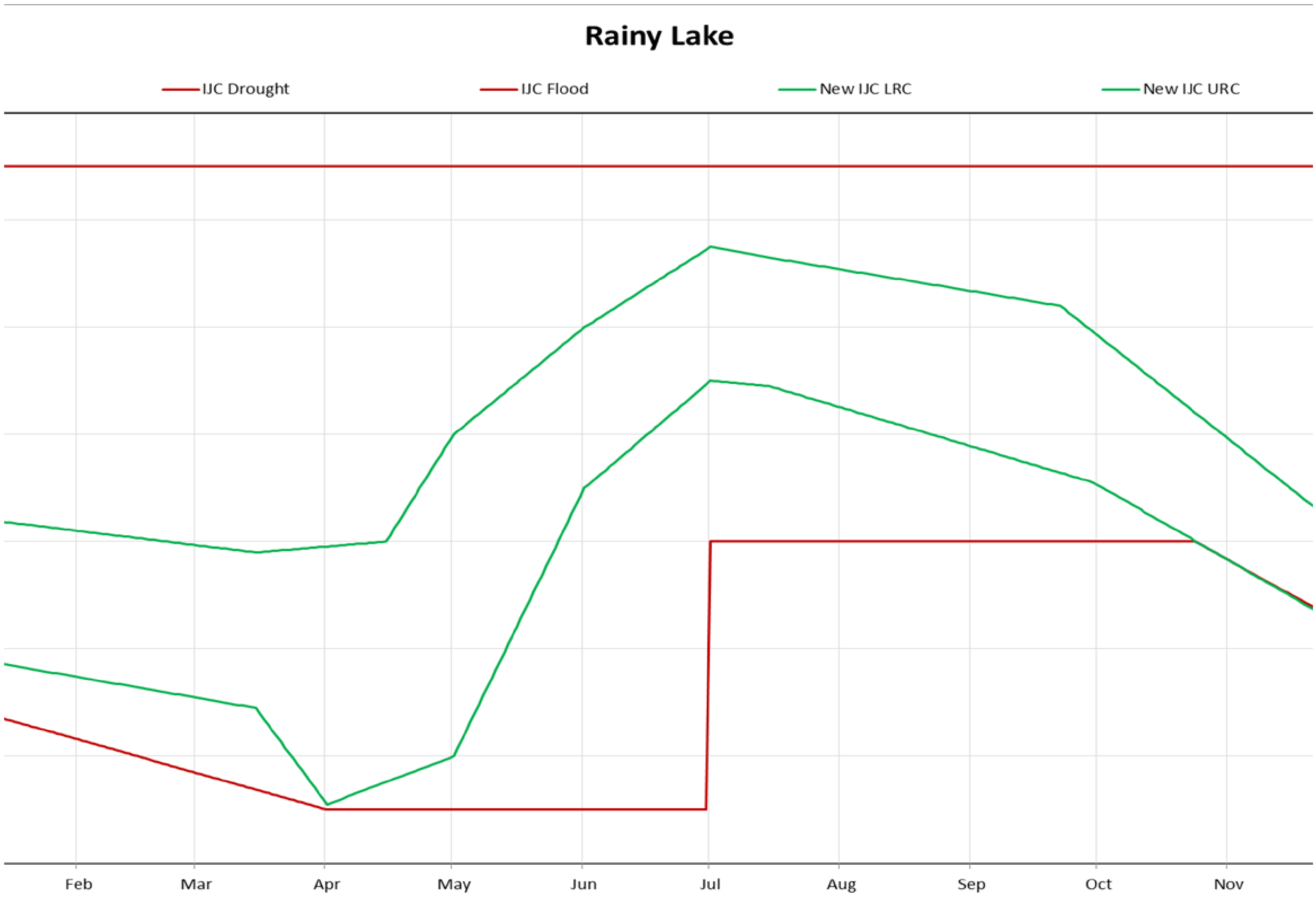
- Each reservoir/river system is unique!
  - Provincial, Inter-provincial, international rules.
- WMP mandated constraints:
  - Max & Min elevations
  - Ramp rates
  - Minimum flows
    - Instantaneous, hourly average, daily average
- Seasonal & stakeholder considerations
  - Navigation, Fisheries, Water quality
- Planning timeframes
  - Months for macro level strategy
    - Drawdown, refill, summer operation
- Weeks for small scale adjustments
  - Weather related, short term deviations

Lake Abitibi - LRIA WMP Rules



Rainy Lake - IJC Rules

- International treaty governs
- Ordered pair elevation rule curve for each day of the year
  - “Stay between the lines”
  - Generator has no authority to move outside the curve without seeking express authorization.
  - Some latitude for inter-day shaping
  - Must pass daily volume to stay within curve.
  - Minimum flow constraints
  - IJC can issue Supplementary Orders to adjust discharge, Generator will comply


Rainy Lake
IJC Drought
IJC Flood
New IJC LRC
New IJC URC
Feb
Mar
Apr
May
Jun
Jul
Aug
Sep
Oct
Nov

Lake of the Woods - LWCB Rules

- International/inter-provincial jurisdiction
- LWCB operates under legislative mandate
- LWCB sets flow directive and updates periodically
  - Pass “X” cms.
  - Very little latitude around target flow.
  - Flow directive and strategy updates generally occurs 2X/yr.
    - Stakeholder consultation, but hydro seems at the lower end of consideration.
    - Relatively slow response time to changing conditions.
  - How flows are utilized is at discretion of Operator.

Cascaded facilities - Single Owner/Operator

- Consider a river system with cascaded facilities
  - 2 or more generating stations in series;
  - Operator owns and/or controls all facilities in series;
  - Hydraulic Lag time between facilities ranges from minutes to hours/days.
- For simplicity of argument, assume no restrictions from Water Management Plans
  - **Operator can schedule facilities in sequence and manage the water supply**

Cascaded River System - Single Owner

- In reality, WMP rules govern operation of hydro plants:
- Owner/Operator has:
  - full control of reservoir management, within WMP constraints;
  - Control of scheduling of GS's;
  - Full knowledge of interdependencies between the GS's and the reservoir.
- Scheduling needs to factor in the time lags between all stops in the system;
- Water scheduling must account for hydrological cycle:
  - Days, weeks, months of lead time to move water into position.
- Time lags are NOT fixed, but a function of system flows.
  - Dynamic, seasonal.

Cascaded River System - Single Owner - Image

Reservoir

- Multi day storage, defined elevation max & min (seasonal)
- Operating rules constraints (LRIA WMP, IJC, other)
- Discharge planning time frame - months

GS1

- Time lag from reservoir to GS1: high/normal/low flows
- Defined elevation max & min (daily, seasonal)
- Ramp rates for loading/unloading (cms/time unit)
- Spillway configuration/capability: gates/stoplogs, seasonal issues, control (local/remote), Public Safety issues

GS2

- Time lag from GS1 to GS2: high/normal/low flows
- Local storage capacity to buffer flow deviations
- Defined elevation max & min (daily, seasonal)
- Ramp rates for loading/unloading (cms/time unit)
- Spillway configuration/capability: gates/stoplogs, seasonal issues, control (local/remote), Public Safety issues
- Downstream flow constraints: minimum flows (instantaneous, hourly, daily)

Cascaded facilities – Multiple Owners/Operators

- May have no control or influence of upstream discharge.
  - At best, may have some communication of a flow change after the fact.
  - No legal requirement to pass water above WMP minimum flows (where they exist).
- Have no incentives to coordinate schedules at the Operator level:
  - Other Operators are the Competition.
  - Does IESO have a coordination role in this?
- Not all GSs in cascade are dispatchable:
  - Not all cascaded GSs are Tx connected!
  - Mattagami River, Trent River, Wahnapetei have Dx as well as Tx connected plants in cascade.
- Some Tx connected GSs are classed as intermittent by virtue of other constraints (environmental, size).

Cascaded facilities – Multiple Owners/Operators - Image

Reservoir

- Multi day storage, defined elevation max & min (seasonal)
- Operating rules constraints (LRIA WMP, IJC, other)
- Discharge planning time frame – months
- Reservoir operator could be an independent 3rd party (not a Generator, but a regulatory Agency, eg DPW, MNRF, Parks Canada)

GS1

- Time lag from reservoir to GS1: high/normal/low flows
- Defined elevation max & min (daily, seasonal)
- Ramp rates for loading/unloading (cms/time unit)
- Spillway configuration/capability: gates/stoplogs, seasonal issues, control (local/remote), Public Safety issues
- No requirement to coordinate w/other facilities

GS2

- Time lag from GS1 to GS2: high/normal/low flows
- Local storage capacity to buffer flow deviations
- Defined elevation max & min (daily, seasonal)
- Ramp rates for loading/unloading (cms/time unit)
- Spillway configuration/capability: gates/stoplogs, seasonal issues, control (local/remote), Public Safety issues
- Downstream flow constraints: minimum flows (instantaneous, hourly, daily)

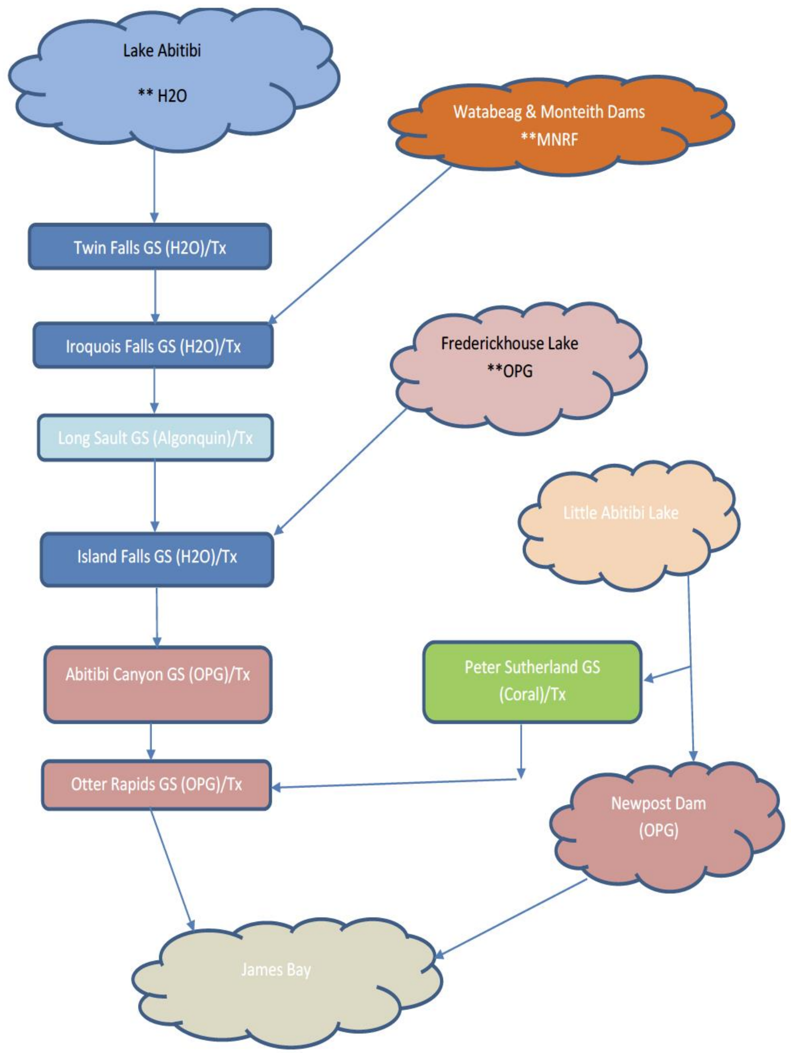
Case Study #1 - Abitibi River

- H2O Power controls upper portion of the river and reservoir (Lake Abitibi);
- Scheduling of Twin Falls/Iroquois Falls/Island Falls governed by WMP requirements for Lake Abitibi & Iroquois Falls min flow;
- Daily storage at Island Falls & Canyon;
- Long Sault Rapids between Iroquois Falls and Island Falls;
- OPG manages Frederickhouse Lake storage (u/s of Island Falls);
- OPG operates 2 large GSs downstream of Island (Canyon & Otter)
- MNRF dams operated w/o prior notification to downstream facilities

Abitibi River watershed

- Combination of:
  - Tx connected dispatchable
  - TX connected intermittent
- 3 separate entities controlling reservoirs
  - 1 direct path to GS
  - 1 indirect path to GS (via another Operator’s facility)
  - 1 non-power producing entity(MNRF) included

Abitibi River watershed - Image



Case Study #1 - Abitibi River

Factors influencing management of the river

2+ days to move 200 cms from Lake Abitibi to Abitibi Canyon GS.
3 mos to draw down Lake Abitibi to make room for spring freshet.
56 cms inst min flow at Iroquois, 10 cms daily ave min flow at Island.
LSR is run of river, with 56 cms inst min flow.
3 separate Operators involved, + influences from MNRF facilities.

Case Study #1 - Abitibi River - Table

Facility	Capacity (MW)	Time lag from U/S facility (hrs)	Cumulative time lag (hrs)	Max Turbine Flow (cms)
Lake Abitibi	0	0	0	(channel limit)
Twin Falls GS	27	24	24	210
Iroquois Falls GS	30	0.5	24.5	250
Long Sault Rapids GS	15	12	36.5	Run of river
Island Falls GS	42	12	48.5	260
Abitibi Canyon GS	350	4	52.5	545
Otter Rapids GS	185	4	56.5	670

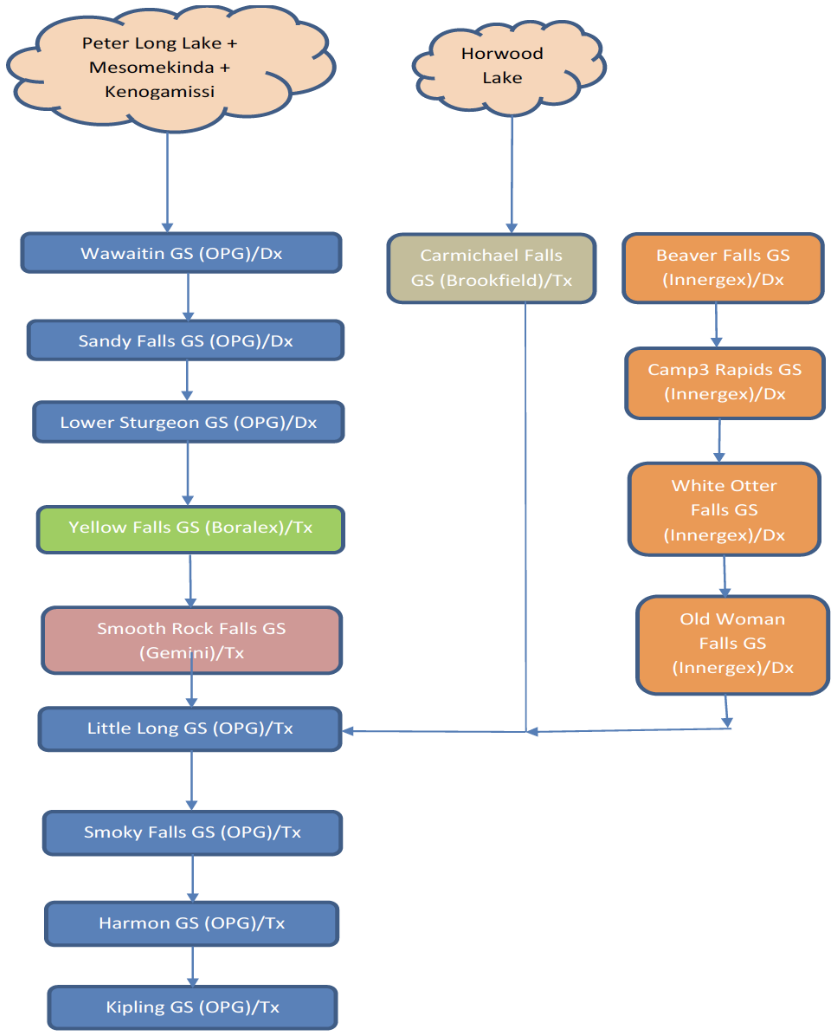
Case Study #2 - Mattagami River

- OPG controls upper portion of the river and reservoirs, 1st 3 GSs (Wawaitin, Sandy Falls, Lower Sturgeon) and lower end of river (Little Long, Smoky Falls, Harmon, Kipling).
- Boralex (Yellow Falls) next downstream from Lower Sturgeon, followed by Gemini (Smooth Rock Falls/SRF).
- SRF WMP headwater limits onerous, requires near instantaneous reaction to any flow change (inflow or outflow).
- Wawaitin, Sandy Falls, Lower Sturgeon are Dx connected.
- IESO has limited Real Time information on these.
- Significant contributions from Groundhog & Kapuskasing River facilities into the Lower Mattagami

Mattagami River Facilities

- Combination of:
  - Dx connected/Intermittent,
  - Tx connected/intermittent,
  - Tx connected/dispatchable.
- 3 river systems merging into a major grouping of large system impactive resources.
- No formal scheduling/staging arrangements between Operators

Mattagami River Facilities - Image



Case Study #2 - Mattagami River

Factors influencing management of the river

Total river length >250km

Upper river facilities Dx connected, not IESO

Yellow Falls, SRF are intermittent facilities

Significant inflows from 2 other sources with Dx and Tx/intermittent resources.

Lower river facilities IESO dispatched

Case Study #2 - Mattagami River - Table

Facility	Capacity (MW)	Time lag from U/S facility (hrs)	Cumulative time lag (hrs)	Max Turbine Flow (cms)
Wawaitin GS	15	0	0	200
Sandy Falls GS	6	6	6	140
Lower Sturgeon GS	14	16	22	200
Yellow Falls GS	18	8	30	160
Smooth Rock Falls GS	9	4	34	60
Little Long GS	180	24	58	750
Smoky Falls GS	270	0.5	58.5	0
Harmon GS	210	0.5	59	750

Issues to consider…

- Need to dispatch the upstream units 1st to move the water downstream
  - Don’t expect upstream facilities to simply pass water to satisfy downstream generation schedules.
- WMP constraints.
- Spillways are for excess flows.
- Flows aren’t uniformly predictable:
  - Transit times proportional to flow
  - Seasonal variations
  - Unregulated inflows difficult to quantify accurately

What Hydro operators are looking for…

- Schedules that efficiently merge WMP requirements with System requirements.
  - ***<u>Taking a finite renewable energy block and best shaping it in volume and time to best meet System needs in an efficient manner.</u>***
    - Short term (hourly, daily);
    - Mid term;
    - Long term.
- Sensible dispatch instructions that don't negatively impact longer term facility reliability.
  - Longer dispatch intervals?
  - 2nd DAM run to optimize hydro contribution?

Using Hydro efficiently

- Basic principle: Use water as efficiently as possible
  - Efficient use leads to:
    - Improved revenues for operators;
    - Lower O&M cost for operators;
    - Lower energy cost for electricity system;
    - Better compliance with regulatory objectives.
- Inefficient use leads to:
  - Higher Operator (and system) cost;
  - Reduce revenue and facility value

ONTARIO POWER GENERATION

700 University Avenue

IESO Stakeholder Engagement

December 9, 2019

OPG Comments –

Market Renewal Energy Workstream Detailed Design; Hydroelectric Dispatch Data

OPG provides the following comments on the Hydroelectric Dispatch Data detailed design materials[1] which formed the basis for the discussion at the meeting held on November 14, 2019. As the IESO's business case[2] for the Market Renewal Project (MRP) relied on the realization of greater efficiencies and reduced system costs from the increased utilization of hydroelectric resources, these comments also highlight the potential reduction of stated business case benefits if these efficiencies are not achieved.

1.0 OPG's Position

OPG strongly requests that the IESO reconsider the approach originally considered during initial stakeholder-IESO discussions (through the High Level Design (HLD) process) where hydroelectric facilities would offer identical price laminations throughout the day in the day ahead (DA) timeframe, thereby allowing the IESO scheduling tool to optimally shift hydroelectric supply to hours of greatest system need. The IESO is in the best position to schedule hydroelectric resources for the system's benefit given their view of the system, knowledge of the offer stack and system optimization objective function. In order to achieve efficient system optimization the discussed set of hydroelectric operational constraints need to be respected, which leads to OPG's concerns that the IESO has indicated challenges regarding the modeling of intertemporal dependencies.

OPG's request to accommodate hydroelectric constraints is the same as the modelling of operational constraints for pseudo units of CCGTs - effective modelling of hydroelectric resources is just as essential for an efficient and feasible system optimization.

2.0 MRP Business Case

The business case for MRP outlined a position for delivering enhancements through:

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[1] http://ieso.ca/-/media/Files/IESO/Document-Library/engage/mrp-edd/edd-20191114-hydroelectric-dispatch.pdf?la=en

[2] http://www.ieso.ca/-/media/Files/IESO/Document-Library/market-renewal/MRP-Energy-Stream-Business-Case-2019.pdf?la=en

- More efficient use of interties
- Better commitment of resources
- Greater competition between resources.

OPG supports these three objectives and strongly supports the efficient use of hydroelectric resources to realize the benefits associated with better commitment of resources as this ultimately results in lower costs for the system and the customer.

The MRP business case analysis (presented at the September 24th MRP Update meeting), concluded that ~$193M of efficiency benefits could be gained in the first 10 years of MRP through more efficient utilization of existing assets. In the quantification[3] of benefits, the unit commitment inefficiency calculation removed committed resources and re-dispatched the system by utilizing offers from other market participants including quick-start units - primarily hydroelectric resources. The analysis reinforces OPG's position that the flexibility of quick start assets, when viewed through the wider lens of overall system optimization, is key to realizing the efficiencies that the IESO presented in the MRP benefit case.

Ontario's bulk electricity system was designed around our uniquely flexible hydroelectric resources. It must be noted that hydroelectric flexibility is only available by ensuring its operating constraints are respected. The failure to adequately model the operating characteristics of these resources would limit their flexibility in a renewed market and would lead to stranding of customer value from existing Ontario hydroelectric assets.

3.0 Value of Hydroelectric Generation

3.1 Flexibility

The IESO has acknowledged the importance of Ontario's hydroelectric resources both at the outset of the MRP initiative and more recently in the MRP benefit case, stating hydroelectric "resources represent nearly one-quarter of Ontario's available capacity and it is important for broader market efficiency that the design enables them to be effectively optimized." [4] The IESO's pre-reading document issued for the November 14th meeting, fails to recognize the full system benefits provided by these resources. The focus on constraints that need to be considered for hydroelectric resources and mitigation of Day Ahead Market (DAM) financial risk does not go far enough to capture the value of hydroelectric resources, such as, peaking and ramping capability, flexibility, and emission free characteristics.

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[3] http://ieso.ca/-/media/Files/IESO/Document-Library/engage/mrpum/mrpum-20190924-energy-stream-benefits.pdf?la=en

[4] Business case…Section 3.3

In discussions, certain individuals at the IESO have stated on multiple occasions that they do not consider hydroelectric facilities to be flexible. OPG strongly disagrees with this statement as hydroelectric assets have and will continue to respond to meet Ontario's evolving system needs and serve as critical backup to intermittent wind and solar generation.

In the DAM HLD Section 3.4, the IESO stated, "Modelling additional hydroelectric operating characteristics is important to the efficiency of the wholesale market since hydro units are frequently dispatched as the marginal resource." This statement demonstrates the flexible role hydroelectric resources provide by following 5 minute dispatch and providing operating reserve.

3.2 Ramp Capability

Ramp capability provided by hydroelectric resources has been an important feature in Ontario to manage contingencies, changing supply mix and system flexibility requirements. However, without having ancillary ramp products as other jurisdictions do such as CAISO, the ramping capability of hydroelectric resources in Ontario is undervalued. The value of ramp is further suppressed by the use of 3x ramp rate in the unconstrained price setting run. Without proper economic signals to indicate where ramp can provide the greatest system benefit, the IESO is in the best position to schedule resources to meet its overall system needs most efficiently.

The IESO's pre-reading material suggests that market participants via their offer strategy would determine the hours over which a cascade would be utilized. Currently, the only market signal available to market participants in advance of the day ahead is forecast Ontario demand. The day ahead least cost solution's use for hydroelectric resources may be demand peaks or it may be more cost effective to be used in the ramp hours leading up to demand peaks (to avoid inefficient commitment of Non-Quick Start (NQS) units). Forecast Ontario demand fails to provide this signal.

Based on the IESO's proposal, hydroelectric market participants would be forced to speculate in which hours their facilities should be scheduled to yield the most efficient system outcome. A participant's narrow view (only its own offers) of the total offer stack would result in an inefficient selection of cascade hours and subsequent utilization of assets. An attempt to correct a potential inefficient selection of hours by the participant in pre- dispatch would expose them to a DA to RT buyback financial risk or a physical risk of an unrealistic schedule which would dis-incentivize the participant in making a change. This approach would effectively render hydroelectric resources inflexible, resulting in NQS units being scheduled "around" the fixed schedules of hydroelectric resources in contrast to a more efficient system optimization model that schedules hydroelectric resources to minimize uneconomic NQS schedules. It is the latter that achieves the maximum benefit to the customer.

During the meeting, the IESO acknowledged that none of the technical vendors nor the IESO understand how to adequately model the intertemporal dependency constraints. While OPG appreciates the complexities of hydroelectric modelling, it was recognized from project inception that Ontario is unique and requires a made in Ontario solution that uses existing resources to their full extent.

4.0 Enhanced Pump Storage Utilization

The IESO HLD has excluded opportunities to address energy storage devices that could allow further optimized usage of pump storage for system benefit. The IESO's vendor RFP (Schedule 2 to Appendix D, pp78-80) includes enhancements for energy storage that is similar to the interim solution the IESO proposed to the Energy Storage Working Group. Of these, the most controversial is the requirement to register as two separate resources (generation and load) instead of creating a new resource category for energy storage that treats load as negative generation. It is imperative in any model the IESO implements that a resource does not receive conflicting DA financially binding schedules for both generation and load in the same hour.

The IESO's hydroelectric additional parameters may facilitate increased use of Beck pump storage through the intertemporal dependencies between resources on a cascade. The PGS resources could be modelled as linked to Beck II generation; however, the IESO would need additional parameters to link both generation and load sides of the optimization. In addition to a parameter that tracks the DEL (or 'state of charge') in the reservoir, a parameter for the ratio of upstream generation to downstream generation would be required.

5.0 Hydroelectric Dispatch Data

The following are OPG's comments on the new dispatch data categories to represent hydroelectric operating constraints:

5.1 Minimum Hourly Output (MHO)

The IESO clarified that the MHO, similar to Minimum Loading Point for NQS resources, will not set price. OPG distinguished between hard (physical) constraints where water must flow through the turbine in a specific hour versus soft constraints, where the flow could be maintained through spill. Hard constraints are similar to the technical limitations (e.g. MLP) faced by NQS resources. The IESO acknowledged this difference in constraints and agreed to further evaluate this requirement. Treatment of MHO needs to accommodate revisions from day-ahead through to real-time since constraints are dynamic.

5.2 Daily Energy Limits (DEL)

OPG's comments provided for DEL are dependent on the outcome for the optimization solution to respect intertemporal dependencies on a cascade.

If cascade dependencies cannot be modelled, OPG provides the following comments on DEL:

OPG encourages the IESO to further define the interactions between MHO and the Minimum Daily Energy Limits. Additional clarity is necessary to determine the impact on the treatment of hard versus soft constraints and the impact on LMPs. OPG emphasizes the need for the ability to change DELs in real-time and for hourly market participant reports to provide a clear indication of IESO accounting of actual DEL and forecast DEL usage in a calendar day. The above questions not withstanding, OPG is supportive of the proposed framework dealing with minimum/maximum DEL and the utilization of shared DEL's when utilized in combination with additional hydroelectric dispatch data.

If cascade dependency constraints are modelled and the IESO optimizes hydroelectric resources rather than market participants, a mechanism needs to be in place to represent the different price laminations or opportunity cost of hydroelectric storages. This could be represented by DEL at different offered prices as described in the HLD. This field would be utilized to provide the flexibility of hydroelectric storage at different opportunity costs and prevent a resource from being over-scheduled in the DA at an offer price that is not reflective of the opportunity cost of the resource.

With only a single DEL, hydroelectric resources may not be able to participate as fully in the DAM, as they may need to reduce the DEL offered to align with base water and essentially only offer opportunity cost water in RT.

5.3 Maximum Starts per Day

It will be important for participants to receive a private report updating the number of starts that were incurred throughout the operating day.

5.4 Forbidden Regions

OPG supports the direction to remove forbidden regions from PQ pairs. Due to the dynamic nature of forbidden regions, OPG recommends they be submitted as daily generation data rather than registration data to reflect different opportunity costs across the varying capability of the resource.

5.5 Intertemporal Dependencies on a Cascade River System

DAM optimization is the IESO's opportunity to use the hydro modelling parameters for system optimization (efficient commitment of all types of generating units) by modelling intertemporal dependencies for cascade river systems. This time parameter is very similar to the lead time parameter for NQS generators. Both intertemporal dependencies and NQS lead times are physical constraints that enable resources to receive feasible schedules in DA and pre-dispatch.

Similar to NQS units, energy limited hydroelectric resources have the flexibility to provide energy and operating reserve in various combinations at both the station level and on the cascade of stations as a whole. This flexibility of cascade river systems is similar to NQS units: dependent on lead time to set up forebays and physical constraints for safety, equipment protection, and applicable law.

In today's pre-dispatch and RT market schedules, both NQS and hydroelectric cascades self commit based on market signals in IESO pre-dispatch. NQS units invoke the RT-GCG program which then constrains the units to at least MLP for MGBRT. In order to achieve the same objective, hydroelectric units are required to self commit using offers potentially below marginal cost.

In many ways, the hydroelectric modelling parameter intertemporal dependencies should be considered the hydroelectric equivalent to lead time and pseudo unit commitments. For market fairness amongst technologies, it would seem equitable to model both types of physical constraints in a renewed market.

The following is an example of a situation where problems could occur if intertemporal dependencies are not respected.

Example:

- GEN A, GEN B, and GEN C are located on a cascade river with 5 unit hours of water/fuel available in the GEN A forebay.
- Due to short hydraulic travel times between stations and the minimal storage available at downstream stations:
    - 50 MW GEN A is linked to 60 MW GEN B with t+0 hours cascade linkage.
    - 60 MW GEN B is linked to 70 MW GEN C with t+1 hour cascade linkage.
- The 5 unit hours of water can either be generated or spilled; the water management plan requires the water to be discharged on a daily basis.
- There are an additional 2 unit hours available for contingency. Precipitation forecasts indicate possible increases to inflows in the next month – not before.
- 5 unit hours offered at cost with the following DEL:
    - GEN A 250 MWh
    - GEN B 300 MWh
    - GEN C 350 MWh

Scenario(s) 1: Intertemporal Dependency and DEL are modelled by IESO.

1A – The system optimization creates the following day ahead schedule with generation scheduled for morning and evening peaks:

- GEN A 50 MW in HE9, 10, and HE18, 19, 20.
- GEN B 60 MW in HE9, 10, and HE18, 19, 20.
- GEN C 70 MW in HE10, 11 and HE19, 20, 21.

1B – A transmission circuit outage requires local generation in the GEN A, B, and C area during off-peak hours. The system optimization with intertemporal dependencies and DEL creates the following day ahead schedule:

- GEN A for 50 MW in HE1-HE5.

- GEN B for 60 MW in HE1-HE5.
- GEN C for 70 MW in HE2-HE6.

In both scenarios 1A and 1B, the intertemporal dependency of the cascade and DEL are respected and feasible day ahead schedules are created. The day ahead schedules are very different from each other, reflecting the flexibility of hydroelectric resources to meet differing system optimization objectives.

Intertemporal dependencies are a system optimization tool which allows the market to solve for the schedules with the maximum system benefit.

Scenario 2: Intertemporal Dependencies are not modelled by Day Ahead Engine, the Day Ahead schedules are:

- GEN A 50 MW in HE9, 10, 11, 12, 13, 14.
- GEN B 60 MW in HE9, 10 and HE18, 19, 20.
- GEN C 70 MW in HE10, 11 and HE19, 20, 21.

The DEL for each station is respected based on day ahead schedule, however, the schedules do not respect the energy limited nature of the cascade river as a whole.

- The schedule is feasible for GEN A and GEN B in HE9 and HE10 and GEN C in HE10 and HE11: it respects both DEL and cascade linkages.
- Infeasible schedules on the cascade for HE11, 12, 13, 14, 18, 19, 20, and 21.
    - The GEN A schedule for HE11, 12, 13, 14 would require GEN B and GEN C to either spill or be offered to generate in real time using the water that was scheduled in Day Ahead for HE18, 19, 20, and 21.
    - The market participant will need to choose whether to generate in RT to meet the GEN A day ahead schedule in HE11, 12, 13, 14 or the GEN B and GEN C day ahead schedules in HE18, 19, 20 and 21.
    - The infeasible schedules create a known systematic divergence between day ahead and real time schedules and LMPs that could be prevented by the IESO choosing to model cascade linkages.

6.0 Next Steps

OPG supports a transparent stakeholdering process and disagrees with the IESO's recent approach to discontinue the posting of participant submitted comments from the technical detailed design meetings. OPG believes these are valuable records of the discussions and viewpoints of participants that provide insight and rationale for the decisions made in the detailed design which can be referenced in future discussions. Other interested parties (e.g. Technical Panel members) who are not intimately involved in the engagement would also be able to rely on these documents to understand the current issues prior to waiting until Q2/Q3 2020 when participants respond to the official release of the detailed design. OPG strongly encourages the IESO to post these comments on their website with regard to the November 14th meeting.

OPG is committed to working with the IESO, its vendor and other market participants to develop a solution that respects the physical constraints of cascade river systems in a market construct that continues to bring value of existing assets for the customer. The IESO has scheduled the next Hydroelectric Dispatch Data meeting for February 6, 2020. OPG would like the IESO to consider using a workshop format and include the vendor in the meeting. Together we may be able to arrive at a feasible solution.

If despite best efforts, the vendor is unable to model hydroelectric constraints, alternate solutions that can preserve hydroelectric benefits should be explored. Other competitive markets with less hydroelectric supply have found unique solutions to integrate their hydroelectric resources. This further supports that Ontario, with an abundance of hydroelectric supply, even more so requires a 'made in Ontario' solution- one that balances MRP's objectives for competition without compromising efficiency.

We look forward to future discussions.

Lynn Wizniak

Ontario Power Generation

[redacted]

IESO Engagement

From: Mike Zajmalowski

Sent: December 19, 2019 1:51 PM

To: Jason Grbavac

Cc: IESO Engagement

Subject: FW: Hydro Electric - Dispatch Data - Detail Market Design

Hi

I'm providing these comments/questions in advance of the November 14th detailed design working group session

As I started reading the document, I was getting the urge to want to explain how the limitations with Hydroelectric facilities work and what flexibilities exist or don't. So I'm going to start my comments with a 101 if you will on hydroelectric offers because I realize that this type of generation is probably where the IESO is lightest on understanding the operational characteristics of these types of facilities:

- One needs to understand that scheduling hydroelectric power all starts at the top of the river. At the top of the river is usually a massive lake that stores water, sometimes seasonally. This is not the forebay/reservoir that a facility would own, but this is crown land. The MNR (or other government agency) regulates the flow of this water including the dams that are up stream to the facilities throughout the year. Between this massive lake and the actual reservoir of the first power plant down the river are also streams and smaller rivers that flow into the main river. This all impact the amount of water that is flowing toward a hydro power plant. The actual reservoir at the top of a power plant has established minimum and maximum elevations. These elevations are regulated and must be respected. This is where you get the Regulatory/Environmental restrictions that is often cited when not following dispatches. The min/max elevation range changes in the summer time (much tighter) and the winter (much wider). Some facilities have no difference in operating ranges between summer/winter. The reservoir at the very first hydro plant on the river typically has the biggest reservoir.
- The #1 takeaway from a hydroelectric river in how production changes from day to day is that on a daily basis the strategy normally is to pass inflows. Meaning whatever is flowing into the first power plant on the river, should go through the penstocks/turbines and continue downstream to the next power plant. For the cascading plants downstream they will also have to pass the same inflows + there may be other streams that flow into the river between the two stations so the production may increase slightly (or decrease), however it's generally the same. This continues all the way down the river until the very last plant. The strategy about passing inflows generally holds for most of the year. Exception being that before freshet, you would pass more than inflows so that you can draw down your reservoir to the minimum because you know you're going to get a surge of water coming that will fill it right back up. Throughout the year you'll have other restrictions like limitations on how low the water can drop in the summer during fish spawning season (can't have eggs exposed to air), or in winter time when reservoirs are trying to build an ice sheet on top of the reservoir (lose cycling capability for a few days). Otherwise you're passing inflows. You have some flexibility in increasing or decreasing by a small amount of water each day based on opportunity. If the temp today is 20 Celsius, but tomorrow is supposed to be 30 Celsius and the next day 35 Celsius, then you can likely run a bit less the first day so that you're saving some water for the 2nd or 3rd day assuming prices are going to be higher. However the general hours of the day that you're scheduling water normally follow the demand curve because that correlates well with pricing. So when you're talking about the challenges that a hydro plant has in scheduling water from day ahead to real time, the variability shouldn't be that different from one

day to the next (assuming no massive increase in water flow) and the difference in hourly production from one day to the next is the same.

Comments from pre-reading

- On page 6, section 3.1 – the statement “Some hydroelectric resources have minimum hourly must run conditions that apply to one or more hours of a dispatch day. These requirements are governed by safety, regulatory and environmental restrictions that can vary on a daily, weekly or seasonal basis.” – Something that is missing from this statement and is probably the biggest factor of all is “equipment damage” When facilities are being oscillated up and down all day it increases the potential for breakage and therefore the variable O&M cost goes up. There aren’t really regulatory and environmental restrictions preventing hydro plants form starting and stopping all the time (that’s what many of them were designed to do). For sure there are some plants that have minimum flow requirements for some hours of the day, but the flow requirement is as per above, which is a daily flow requirement to pass inflows. So if you’re being oscillated up and down all day, then by the end of the day you’re having a hard time passing inflows, and then you’re running uneconomic at the end of the day. Having minimum run conditions is more of an economic choice so that you’re not running uneconomic by the end of the day as you try and pass inflows for that day.
- Given that flows don’t change much from one day to the next, and hourly production doesn’t change much from one day to the next, my biggest recommendation and I can appreciate it may be challenging is to give hydro plants the flexibility to schedule and manage their financial price exposure on a river, not just the facility. The IESO will get very accurate results. The IESO would then just have to give itself flexibility that under system conditions you can require certain production out of certain facilities to alleviate transmission concerns.
- Assuming no congestion or voltage needs, the IESO may be agnostic to where on the river system the energy is coming from. The challenge for hydroelectric facilities that have either small reservoirs or short time in between plants is that if you run one plant out of merit (ORA or price spike), you may not have enough time to adjust schedules and it will have a cascading affect downstream to the other facilities. You can turn your whole schedule upside down by just having a few hours run different than you originally scheduled. When there’s price risk exposure that’s a major risk.
- On bottom of page 6 – “Other jurisdictions provide their market participants with the ability to specify their hourly minimum energy requirements. If applicable, these minimum hourly energy requirements are typically registered as a single value well in advance during market registration and cannot be updated on a daily basis as dispatch data. This single value is used for every hour of the dispatch day. While this approach helps market participants reduce the risk of receiving schedules below their minimum hourly requirements, it is quite static in nature when considering that hydroelectric minimums in practice can vary hourly from one day to the next.” – this is more so relevant for run of the river plants, but less so for peaking plants. Most plants in Ontario can shut down overnight. Few have this must run requirement (the big ones, and the NW facilities).
- Top of page 7 – “The IESO considered the possibility for market participants to submit non-dispatchable hourly quantities for hydroelectric resources into the DAM and PD calculation engines. However, enforcing an above zero schedule could cause a security limit such as a thermal rating on a transmission line to be violated if the resource could not be scheduled to 0 MW to respect the transmission line rating.” – Does the IESO require or do facilities register “time to initiate spill”? If you know that a facility needs 4 hours to clear all safety, regulatory, environmental and equipment damage hurdles then knowing that, you can still have a 0 MW value as long as they can spill the water and avoid exceeding other restrictions.
- Page 7 – 3rd paragraph – “Another similarity to a NQS resource’s minimum loading point is that hydroelectric resources could continue to be scheduled for operating reserve above their MHO values.” Would the IESO schedule operating reserve from a facility below their MHO, or would they only schedule above their MHO? For dispatch it would respect the MHO but is that the same for scheduling?

- Page 7 – bullets – “Market participants may submit MHO values as part of their dispatch data. The following data validation rules will apply when the market participant submits an MHO value:” – Would the IESO follow the same level of scrutiny and perform due diligence as it does with Thermal facilities when they want to change their MLP, MRT, or MGBRT? What validation or audit is completed to confirm that the reason provided was legit?
- Page 10 – Section 3.2.3 – “Currently, market participants submit a separate DEL for each of their hydroelectric resources. While effective for most resources, there are some resources that draw water from the same forebay where the single DEL per resource parameter may create challenges.” There’s maybe one or two plants that may share the same reservoir (I can only maybe think of 1). They all share the same upper reservoir as described above, but that has no impact on the daily operations of a hydroelectric facility. There are some power plants that are very close to each other, so the reservoir is very small, but that’s not what you’re stating here. This whole section seems moot.
- Page 10 – bottom paragraph – “To address this limitation, the IESO will provide market participants with the option to identify resources that share a DEL. This relationship will be captured through facility registration, and the DAM and PD calculation engines will be enhanced to use the registration data to ensure that schedules produced for those resources respect the same DEL and MDE constraints.” Can resources be whole facilities? Could this address my recommendation that the whole river system should be modeled as one and managed as one? Can you identify an entire river as one DEL and then split up the production as you see fit?
- Page 11 – section 3.3 – first paragraph – “Maximum starts per day is a parameter currently available for NQS resources to reflect the number of times that they can start up and shut down within a given day to avoid equipment failure. These are known as start-up cycles. Similar to Non-Quick Start (NQS) resources, hydroelectric resources have start-up cycle restrictions but have no equivalent parameter to submit.” If you are going to introduce maximum # of starts for a hydroelectric facility you’ll need to define start. Many hydro facilities in fact don’t shut down but instead go on condense or speed no load. Being on condense reduces the equipment damage risk. The concern is completely shutting down and starting up – again the concern should be increased wear and tear and increased O&M costs, not for safety, environmental, regulatory or applicable law – it’s an economic decision. By introducing this definition in my opinion you’re eliminating flexibility that hydro electric resources are designed to provide. Limiting starts is an economic decision because it impacts those other variables. Generators should have the ability to include those costs in their energy offers so why limit the number of starts. There are costs to go on condense or SNL – maybe the IESO should explore paying for this cost to retain the flexibility to use these resources the way they were designed to be used.
- Page 13 – section 3.4.2 – Agree that 3 forbidden ranges is not enough, however if you allow them to schedule on river basis, then more options to manage that, and more certainty to IESO of what you’re getting.

Mike Zajmalowski | Director Market Compliance & Integration Northland Power Inc.

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February 5, 2020

Lynn Wizniak
Ontario Power Generation
Via e-mail to: l.m.wizniak@opg.com Dear Lynn

Re: OPG Comments - Market Renewal Energy Workstream Detailed Design; Hydroelectric Dispatch Data

The IESO would like to thank OPG for their feedback, dated December 9, 2019, on the recent discussion regarding Hydroelectric Dispatch Data, which followed the stakeholder engagement session on November 14, 2019. As stakeholders and the IESO continue these discussions to move towards a detailed design of the renewed energy market, it is worth remembering that significant benefits, as outlined in the Business Case, accrue to the entire Ontario market from this project. OPG has been a key participant in the various stakeholder discussions and forums, and the IESO and the entire sector benefits from their active participation.

These detailed design sessions have been structured to support an interactive dialogue on design elements to inform the forthcoming draft design documents. The IESO will be releasing a series of energy stream detailed design documents which will reflect the comments and feedback received during the detailed design engagement sessions. Stakeholders will be provided the opportunity to comment on these design documents in their totality; comments and IESO responses will be posted on the IESO engagement webpage. This approach follows feedback from the High-Level Design phase, where stakeholders asked for more engagement on potentially challenging design topics, with the ability to view and comment on the design sections as a complete first draft.

In the meantime, the IESO wishes to respond to certain OPG comments in order to confirm the goals and the objectives of the Market Renewal Program, correct any misunderstanding of those objectives, and reiterate the expectations placed on all market participants.

The role of the electricity market in Ontario is to bring together buyers and sellers of electricity to efficiently meet reliability needs. The IESO, through its tools and processes, will optimize schedules and dispatch instructions for all resources based on their bids and offers into the market. In response to OPG's comments in section 1.0, and similarly echoed throughout the letter, the IESO will not implement an optimization solution, proposed by OPG, based solely on a supplier's production costs. It is up to the supplier to submit marginal costs, which can include production costs, opportunity cost, and other considerations reflecting how they value the resource's available energy in each hour. This is a fundamental concept underpinning today's electricity market and the future market.

Regarding OPG's comments in section 2.0 on the Market Renewal business case and the need for hydroelectric flexibility to realize those benefits, the quantified benefits were calculated without any specific optimization of cascade hydroelectric facilities but based on better optimization of all available resource types – some of which are hydroelectric. The business case does indicate that the renewed energy market will enable market participants to submit additional data and information to better reflect the physical realities of specific resource types (including hydroelectric). This will provide for greater operational flexibility and more efficient unit commitment thereby unlocking the value of these assets to the benefit of the system and customers, in addition to the quantified benefits in the business case.

The efficiency benefits included in the business case are a result of the more efficient utilization of all assets, based on their submitted information into the dispatch algorithm. Based on the comprehensive analysis within the business case, the IESO believes that the conservative benefits calculated through the business case will be achieved through the implementation of the Market Renewal Program.

From section 3.0, the IESO agrees that there is significant value from attributes that hydroelectric resources provide. The IESO will continue to engage with stakeholders and has committed to another session specifically focusing on cascade hydroelectric dispatch data on February 6, 2020. For items that are not in scope for the Market Renewal Program (e.g. ramping products and peaking capability) the Market Development Advisory Group is the appropriate forum to discuss and prioritize these issues in the context of how best to meet system needs, including examining new market-based products. The IESO recognizes that hydroelectric assets can provide flexibility, and are important system assets. However, the role of the IESO and the role of OPG, or any other market participant, is fundamentally different. The IESO administers the market to produce efficient outcomes in delivering a reliable power system through transparent market structures and signals. This optimization is a function of the bid and offer data submitted from market participants, subject to constraints directly associated with the production of electricity. Competitive bids and offers reflect participants' willingness to pay or be paid for energy and reserves, and the market maximizes the gains from trade from these transactions. The IESO's role is to create a market environment that has the incentives in place for market participants to make decisions that maximize their benefit, and in turn, the market as a whole. The IESO is currently in the process of redesigning the energy market, so that the dispatch algorithm can better use the accurate bid/offer data and resource constraints.

Regarding the comments in Section 4.0, the IESO recognizes that the inclusion of storage, and pumped storage, in the IESO administered market brings complexities and significant opportunities. The Energy Storage Advisory Group is actively prioritizing and pursing options to enhance the participation of energy storage in the Ontario market.

The IESO appreciates the feedback on the topic of hydroelectric dispatch data in section 5.0, and the examples of intertemporal dependencies on a cascade river system in section 6.0. The MRP design team will consider those comments as work on the detailed design continues, and as we collaborate to find a solution to the unique challenges of generation resources on cascade river systems. The IESO will continue documenting feedback and report how the feedback was used to inform the detailed design of the renewed Energy market. Thank you for your continued commitment to participating in the IESO's various stakeholder engagements and providing constructive feedback to support the sector's efforts to enhance Ontario's energy markets.

Sincerely,

IESO Engagement