Power Advisory LLC

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Dear Shawn,

On May 5, 2020, the Independent Electricity System Operator (IESO) released the draft *Market Power Mitigation Detailed Design Issue 1.0*.[1] This document is part of a series of draft detailed design documents defining how the IESO-Administered Markets (IAM) will be fundamentally reformed through the IESO Market Renewal Program (MRP) initiative.

Power Advisory LLC has coordinated this submission on behalf of a consortium of renewable generators, energy storage providers, and industry associations (i.e., the "Consortium"[2]) providing comments on the draft *Market Power Mitigation Detailed Design Issue 1.0*.

GENERAL COMMENTS AND RECOMMENDATIONS

The Consortium understands and accepts that market power mitigation, that will be administered by IESO, is a needed feature within the IAM, as is the case with all other wholesale electricity markets.

However, IESO is proposing to implement a market power mitigation framework predominantly used within the U.S. wholesale electricity markets[3] without sufficiently taking into account significant differences regarding the structure and organization of Ontario's wholesale electricity market. As a likely consequence, IESO's proposed market power mitigation framework may overly mitigate some areas within the IAM and not mitigate other areas within the IAM.

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[1] See http://www.ieso.ca/Market-Renewal/Stakeholder-Engagements/Energy-Detailed-Design-Engagement

[2] The members of the Consortium are: Canadian Renewable Energy Association; Axium Infrastructure; BluEarth Renewables; Boralex; Capstone Infrastructure; Cordelio Power; EDF Renewables; EDP Renewables; Enbridge; ENGIE; Evolugen (by Brookfield Renewable); H2O Power; Innergex; Kruger Energy; Liberty Power; Longyuan; NextEra Energy Canada; Pattern Energy; Suncor; and wpd Canada.

[3] U.S. wholesale electricity markets (i.e., NYISO, ISO-NE, PJM, MISO, SPP, CAISO, and ERCOT) use a Conduct & Impact Test or a Pivotal Supplier Test as their market power mitigation framework. Both Tests are similar in objectives and scope. NYISO, ISO-NE, MISO, and SPP use the Conduct & Impact Test. IESO has proposed development and administration of a Conduct & Impact Test. Interestingly, the Alberta Electricity System Operator (AESO) does not use similar market power mitigation framework and tests, as used in the U.S. wholesale electricity markets. AESO's market power mitigation is drastically more *laissez-faire*, so as to permit greater ability of resources (e.g., generators) to recover fixed costs through inframarginal economic rents via wholesale energy market revenues within AESO's wholesale market.

The sub-section following the recommendations below lists key Ontario-specific factors that need to be seriously considered when proposing and developing a reasonable, workable, and effective market power mitigation framework within the IAM.

Recommendations

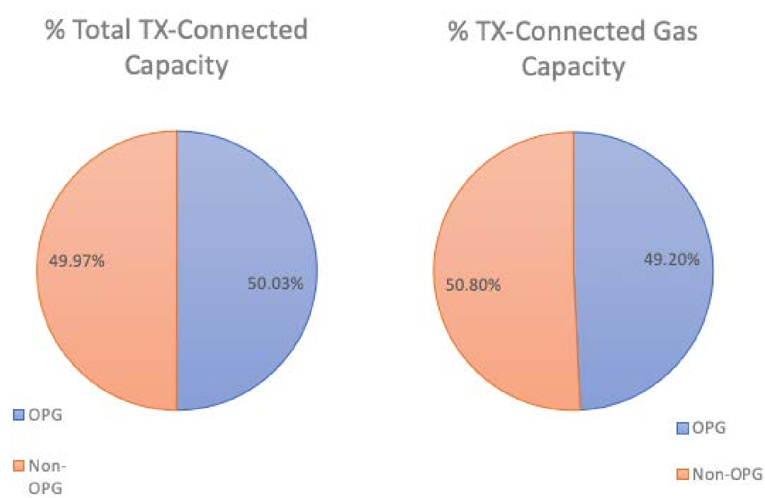
The following are the Consortium's general recommendations regarding IESO's proposed market power mitigation framework.

- Take into account Ontario's specific and unique structural differences compared to the U.S. wholesale electricity markets in the design and rules for a market power mitigation framework for the IAM.
  - This should result in a more stream-lined and efficient framework to mitigate for physical withholding, given energy supply incentives within OPG's forthcoming 'must-offer' supply obligations and contracts for nearly all other generators. This will ensure this aspect of market power mitigation will not 'over-mitigate'.
  - Considering well documented anti-competitive behaviour from demand-side MPs within the IAM, a mitigation framework for demand-side resources should be developed. This helps to unsure that market power mitigation will not be 'under-mitigated'.
  - Especially for sub-zones in the Northwest and Northeast zones, the combination of surplus baseload generation (SBG), 'out of market' incentives and drivers from contracts and rate-regulated frameworks for most generators located in these sub-zones, combined with the potential for offer behaviour from some resources that may change resulting from potential prolonged and very low Locational Marginal Prices (LMPs), a mitigation framework to address predatory pricing and price suppression will likely be needed. This will also help to ensure that market power mitigation will not be 'under-mitigated'.
- Review the efficacy and practicality of the proposed global market power mitigation framework, as incremental imports may not be good indicators of whether global market power is being exercised and therefore need to be mitigated. However, if incremental imports are to be the framework to assess and mitigate global market power, this framework needs to be expanded to include all of Ontario's interconnections.
- Because the proposed Conduct & Impact Test market power mitigation framework will be an impactful and new feature within the IAM, with potential results that could alter the economics of applicable MPs (e.g., generators inside load pockets), IESO should establish a standing market power mitigation stakeholder engagement – not just a lesser scope stakeholder engagement only relating to establishment of reference levels and reference quantities, as announced during IESO's July 24, 2020 MRP update presentation.

Ontario Power Generation Market Dominance

Ontario Power Generation (OPG) is by far Ontario's largest generator by supply market share, most of its generators are rate-regulated by the Ontario Energy Board (OEB), and is solely owned by the Ontario government. OPG's market dominance has always posed potential for OPG to exercise market power. Therefore, this can potentially impact the IAM resulting in potential financial harm to other market participants (MPs) and also potentially deter investments in needed resources towards helping to maintain Ontario's resource adequacy and power system reliability needs[4].

OPG now effectively controls approximately 50% of all transmission-connected supply capacity in Ontario (see figure below), including a significant percentage of faster ramping generators that may set wholesale market-clearing prices for energy and OR under tight system conditions during high price hours. Prior to the recent acquisition of gas-fired generators, OPG owned and operated less than approximately 43% of transmission-connected supply capacity and approximately 25% of gas-fired generators (now owns approximately 49% of all transmission-connected gas-fired generators with the close of the most recent transaction).



Source: Power Advisory, IESO

Prior to May 2002 opening of Ontario's wholesale and retail electricity markets, the Ontario government recognized OPG's potential ability to exercise market power, and therefore implemented a Market Power

[4] For clarity, this submission does not suggest or proport that OPG has exercised, or will exercise, market power within the IAM. This submission does take the position that OPG's ability to potentially exercise market power, given its supply market share, and relevant mechanisms to address their market dominant supply position (e.g., 'must-offer' obligation as a condition to OPG's generator license), must be taken into account within the design of any market power mitigation framework for the IAM.

Mitigation Agreement (MPMA)[5] as a condition to OPG's license to operate as a generator. The main conditions of the former MPMA were a revenue cap of $38/MWh, 'must-offer' supply obligations, and decontrol generation ownership to 35% market share within 10 years. After several years, MPMA was terminated partly due to OPG's declining market share, mainly resulting from retirement of all coal-fired generation and increased supply competition particularly in the operating reserve (OR) market.

However, OPG's market share has since increased based on development of hydroelectric and solar generation projects, and recent acquisitions of gas-fired generators[6]. Acknowledging OPG's increased market share, OEB recently approved amendments to OPG's license with a key condition – conclusion of a 'must-offer' supply obligation with IESO, regarding energy and OR supply from all owned generators[7]. It is the Consortium's understanding that negotiations of this new 'must-offer' supply obligation between OPG and IESO are on-going, and OPG will be filing the concluded 'must-offer' obligation this summer for OEB decision.

In the most recent OEB's Market Surveillance Panel (MSP) report, *Market Surveillance Panel Monitoring Report 32 – Monitoring Report on the IESO-Administered Electricity Markets* (July 16, 2020), released on July 30, 2020[8], MSP has reported on their analysis of OPG considering their increased supply market share. The MSP stated that:

> "By increasing its [OPG's] control of installed capacity – both baseload and peaking assets – the potential risk of the exercise of market power, in the Panel's [MSP's] view, becomes more of a concern. The Panel notes the licence conditions that have been imposed by the Ontario Energy Board to address concerns about market power and the competitiveness of the IESO-Administered Markets, and expects to monitor performance under those licence conditions."

Therefore, considering OPG's dominant market share coupled with the forthcoming 'must-offer' supply obligation, the Consortium is of the opinion that substantial potential to exercise market power within the IAM may then be addressed. However, a market power mitigation framework within the IAM will still be required, but IESO should factor in potential implications of OPG's forthcoming 'must-offer' supply obligations when designing the market power mitigation framework – in particular the physical withholding framework within the proposed Conduct & Impact Test.

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[5] For an overview and rationale for MPMA, see pp. 30-34 from the MSP's first report, *Monitoring Report on the IMO-Administered Electricity Markets for the First Four Months May-August 2002* (October 7, 2002), and pp. 25-27 from the MSP's latest report, *Market Surveillance Panel Monitoring Report 32 – Monitoring Report on the IESO-Administered Electricity Markets* (July 16, 2020), both located at https://www.oeb.ca/utility-performance-and-monitoring/electricity-market-surveillance/panel-reports

[6] See information on OPG's acquisition of gas-fired generators at https://ca.finance.yahoo.com/news/opg-subsidiary-atura-power-finalizes-211100875.html

[7] See OEB Decision and Order (April 9, 2020), located at http://www.rds.oeb.ca/HPECMWebDrawer/Record?q=CaseNumber=EB-2019-0258&sortBy=recRegisteredOn-&pageSize=400

[8] See https://www.oeb.ca/utility-performance-and-monitoring/electricity-market-surveillance/panel-reports, particularly pp. 3, and 24-31

Other Forms of Anti-Competitive Behaviour Requires Mitigation Framework

Market power mitigation should not solely include the ability to exercise market power in order to raise prices above competitive levels resulting from a market dominant supply share position, as is the case with the Conduct & Impact Test proposed by IESO as the market power mitigation framework within the IAM.

Market power can also be exercised resulting from other unilateral anti-competitive behaviour that may not result in price increases above competitive levels, but can distort market outcomes away from competitive levels. The following sub-sections describe two examples of this within the IAM and should therefore be explicitly addressed within MRP in addition to development of the Conduct & Impact Test.

Demand-Side Mitigation

There have been many instances where dispatchable loads have been found to exercise anti-competitive behaviour within the IAM (predominantly through gaming), as has been frequently analysed and reported on by MSP. Many of these instances resulted in dispatchable loads gaming Congestion Management Settlement Credit (CMSC) payments, although these instances are not expected to continue with the implementation of MRP, as CMSC payments will be terminated. However, MSP has reported on instances where dispatchable loads have gamed OR payments.

For example, in MSP's May 2017 report[9], two dispatchable loads were found to receive OR payments even though they were technically incapable of providing OR. MSP stated that "... not only were the DLs [dispatchable loads] potentially compromising the reliability of the grid by operating in a manner which rendered them unable to meet their OR obligation, but they were compensated for such behaviour", and "This unavailable OR issue is much larger than the aforementioned example: from January 2010 to April 2016, the Panel estimates that DLs received approximately $12.5 million in OR payments for reserves that they were incapable of providing. DLs scheduled for ten-minute OR were capable of providing the entirety of their OR schedule in only 9.6% of all intervals during the Current Reporting Period."

The above issue resulted in this MSP recommendation to IESO – "The IESO should take steps to ensure that dispatchable loads are only compensated for the amount of operating reserve they were capable of providing in real-time. More fundamentally, the IESO should explore options for ensuring unavailable OR is not scheduled in the first instance."

The above example clearly shows the need for IESO to explore an explicit demand-side mitigation framework within the IAM, for inclusion within MRP design and therefore within subsequent versions of *Market Power Mitigation Detailed Design*.

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[9] See pp. 5-6 and 73-76 in *Monitoring Report on the IESO-Administered Electricity Markets for the period from November 2015 – April 201*6, located at https://www.oeb.ca/sites/default/files/msp-report-nov2015-apr2016_20170508.pdf.

It is acknowledged that under Section 2.2.4 of the draft *Market Power Mitigation Detailed Design Issue 1.0* regarding dispatchable loads and hourly demand response resources that IESO has stated "… in the event that these demand-side *market participants* receive payments for reducing or avoiding consumption, this design [market power mitigation] should be amended so that they are tested for market power similar to other suppliers of *energy*".

Considering the history of anti-competitive behaviour by some dispatchable loads, not only by the OR example above but also including gaming CMSC payments and at times exercising local market power[10], the Consortium believes there is sufficient historical evidence and therefore need to develop a demand-side mitigation framework within MRP.

Predatory Pricing and Price Suppression Mitigation

Ontario has a set of unique and specific factors that enable potential anti-competitive behaviour through predatory pricing – unilaterally exercising a dominant market position to lower and suppress prices below competitive levels in order to create barriers to participate within the IAM (i.e., causing some resources to not be economically dispatched to supply energy and/or OR).

These following unique and specific factors within the IAM will most likely prevail in some sub-zones within the Northwest and Northeast zones post MRP implementation:

- SBG;
- Prolonged periods of and very low negative LMPs;
- 'Out of market' drivers and incentives to produce energy, even under SBG conditions, from applicable contract provisions for some generators and from the rate-regulated framework applicable to OPG's hydroelectric generators; and,
- Water management requirements at times dictating 'must-run' conditions for some hydroelectric generators.

These are unique and specific factors within the IAM relative to other wholesale electricity markets due to persistent oversupply in some zones and sub-zones, large volumes of contracted generators with particular contract provisions, large volumes of rate-regulated hydroelectric generation, and relatively higher share of hydroelectric generation highly concentrated within specific zones and sub-zones. As seen in the table and graph below for 2019, SBG and negative pricing are significant within Ontario.

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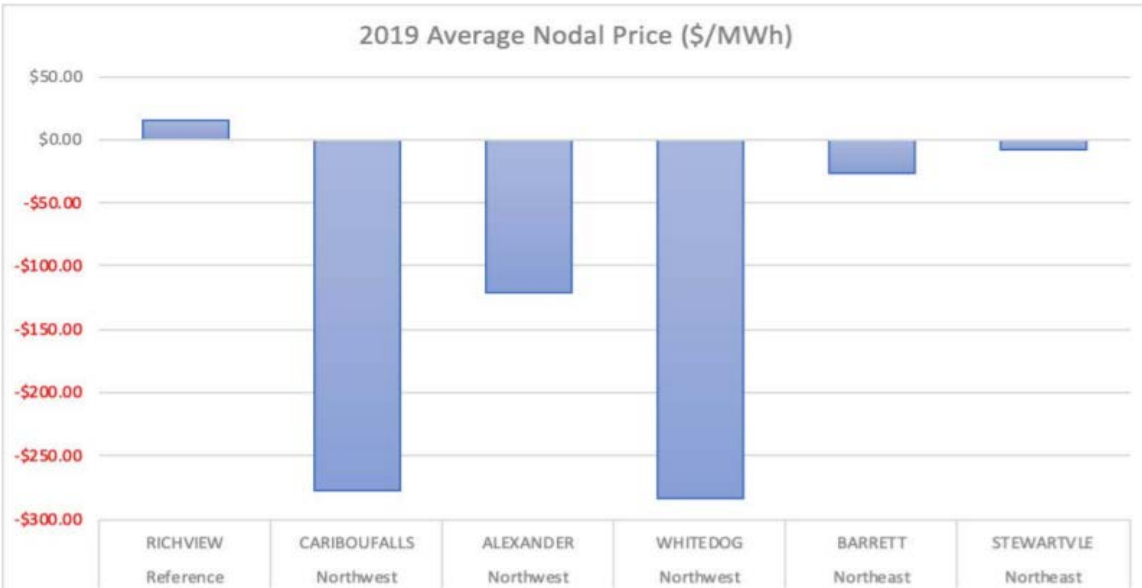
[10] MSP has analysed and reported on multiple CMSC anti-competitive behaviour through gaming and exercise of local market power regarding some dispatchable loads. For examples of MSP reporting on these issues, see the May 2016 MSP report (located at https://www.oeb.ca/oeb/_Documents/MSP/MSP_Report_Nov2014-Apr2015_20160512.pdf) and the November 2016 MSP report (located at https://www.oeb.ca/oeb/_Documents/MSP/MSP_Report_May2015-Oct2015_20161117.pdf).

	IESO	NYISO	MISO	ISO-NE	PJM
Hours in 2019 when Market Clearing Price is $0 or less	1,733	21	2	52	4

Source: Power Advisory, applicable ISO/RTOs



Source: Power Advisory, IESO

By implementing LMPs, mathematically these LMPs will be lower than present uniform and Ontario-wide Hourly Ontario Energy Prices (HOEPs) and five-minute Market-Clearing Prices (MCPs). Therefore, it is reasonable to assume that some generators may change their present offer behaviour and strategies in response to lower LMPs in order to best ensure being scheduled in the Day-Ahead Market (DAM) and committed in pre-dispatch for energy production in the Real-Time Market (RTM).

Changes to offer behaviour and strategies by some generators will also be incentivized by 'out of market' contract or rate-regulated drivers and incentives – which could result in very low negative offer prices that may not be in-line with competitive levels. Consequentially, some resources that had offered in-line with competitive levels, and may relatively be less marginally expensive than other dispatched resources, may not be dispatched and therefore will incur lost revenues (i.e., as the case may be for some generators and importers). Further, from power system and wholesale electricity market points of view, energy may be injected onto the grid during SBG conditions where otherwise it should have been curtailed while wholesale prices become distorted by not reflecting marginal or opportunity costs of energy and/or OR. Overall, this potential dynamic could result in additional costs to Ontario's electricity customers.

The following provides an example of this potential future dynamic of predatory pricing and price suppression potential.

- Any of the following sub-zones[11] contain multiple supply resources: i) Thunder Bay and west to Manitoba (in Northwest zone) mainly comprises of hydroelectric generation, wind generation, dispatchable loads, imports, etc.; ii) immediately east of Lake Superior (in Northeast zone) mainly comprises of hydroelectric generation and wind generation; and, iii) Timmins and east to Quebec (in Northeast zone) mainly comprises of hydroelectric generation, solar generation, gas-fired generators, imports, etc.

- Due to a combination of transmission constraints, low demand, higher than average levels of energy supply (e.g., freshet conditions resulting in higher than average energy supply from hydroelectric generators), any of the three above listed sub-zones could experience prolonged SBG conditions.

- When SBG conditions persist, some energy supply from respective generators will be curtailed by IESO in order to manage local power system requirements.

- Even though today's IAM dispatches (and curtails) based on economics from offer and bid data from MPs, transmission constraints, security limits, etc., under future local SBG conditions, on balance, LMPs will be lower than HOEPs and MCPs.

- Given the elimination of CMSC payments (i.e., specifically constrained-off CMSC payments), resources (e.g., generators, etc.) will receive less financial compensation within the IAM under an LMP pricing regime, as they are being compensated today under uniform prices and operating profit regime of HOEP/MCP and CMSC payments, respectively.

- Therefore, these impacted resources (e.g., generators, etc.) will likely change their offer behaviour in response to LMPs and the potential to be scheduled for RTM dispatch.

- However, if some resources (e.g., generators) have provisions under their contracts or rate-regulated framework that afford revenue certainty based on wholesale price exposure and/or 'must-offer' provisions, then these resources will have incentives and drivers to lower their offer prices to best ensure receiving dispatch instructions to supply energy and/or OR and therefore lessen the potential to be curtailed or not be curtailed at all.

- Consequentially, not all resources (e.g., generators, imports) are afforded with such contract provisions or rate-regulated provisions, and could be financially harmed because they will not

[11] Depending on how sub-zones are defined, sub-zones could comprise of more than one sub-zone. The point of the example is that no matter how many sub-zones are defined, they will at times have distinct transmission constraints that will result in different LMPs relative to the applicable zonal average LMP and different to the present uniform and Ontario-wide HOEP and MCP.

have the same 'out of market' protections to incentivize altering their offer behaviour in the same manner.

- The dynamics described in the above points are further complicated given the significant amount of hydroelectric generation in these sub-zones (which must be sensitive to water management requirements due to statutes and regulations), variability of SBG conditions (in part due to variability of energy supply from hydroelectric generators from year-to-year), new IESO proposed provisions within MRP that will enable applicable 'quick-start' hydroelectric generators to supply energy as 'must-run' resources with minimum energy output, hourly must-run, and/or minimum daily energy limit input requirements[12] that must be achieved, and OPG's 'must-offer' supply obligations as a condition to their generator license.

- So, by using some of the indicative LMPs from the above graph, if HOEP/MCP was $0/MWh in a sub-zone under today's IAM and became -$300/MWh for that same sub-zone under the planned LMP regime post MRP implementation, and the same system conditions prevailed between today's IAM and the IAM with MRP implemented (e.g., sub-zonal demand of 200 MW, same binding transmission-constraints and security limits creating a load pocket, same water availability conditions resulting in same energy supply from respective hydroelectric generators), potential dispatch outcomes could result for the following resources in this load pocket in response to the LMP regime:

    - Hydroelectric generators with favourable contract provisions lower their offer prices accordingly – dispatched by IESO;

    - Hydroelectric generators without favourable contract provisions will have less incentives or insufficiently able to lower their offer prices accordingly – not dispatched by IESO;

    - As proposed by IESO within MRP, wind and solar generators will be subject to offer price floors (i.e., -$3/MWh and for wind generators' last 10% of energy output -$15/MWh)[13], and therefore will not be able to lower their offer prices so as to ensure being dispatched – not dispatched by IESO;

    - As proposed by IESO in MRP, applicable dispatchable hydroelectric generators (whether contracted or rate-regulated) with minimum energy output, hourly must-run, and/or minimum daily energy limit requirements will essentially operate as 'must-run' resources – dispatched by IESO;

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[12] See Table 3-1, p. 18, in the IESO's draft *Offers, Bids and Data Inputs Detailed Design 1.0.*, located at http://www.ieso.ca/en/Market-Renewal/Stakeholder-Engagements/Energy-Detailed-Design-Engagement

[13] See p. 26 in the IESO's draft *Offers, Bids and Data Inputs Detailed Design 1.0.*, located at http://www.ieso.ca/en/Market-Renewal/Stakeholder-Engagements/Energy-Detailed-Design-Engagement

- OPG's rate-regulated hydroelectric generators will be subject to energy and OR 'must-offer' obligations as a condition to their generator license – may or may not be dispatched by IESO, depending on the details of the 'must-offer' obligation;
- Gas-fired and bio-energy generators (merchant or contracted) will not have incentives to lower their offer prices – not dispatched by IESO; and,
- Imports will not have incentives to lower their offer prices, unless they are part of a 'linked-wheel' transaction (i.e., import offer and accompanying export bid, so as to offer into the IAM and simultaneously bid out of the IAM to another market (e.g., NYISO, MISO) – dispatched by IESO if part of a 'linked-wheel' transaction.

- Therefore, if the total amount of all the "dispatched" resources listed above were greater than the applicable sub-zonal demand of 200 MW (from the example), IESO will need to curtail some of these resources. Given the proposed MRP detailed design to date, it is not clear how IESO will decisions on which resources will be curtailed or not.
- The clear point is that resulting from incentives and drivers to at times drastically lower their offer prices, some resources (e.g., generators, imports) will have greater ability than other resources to receive dispatch instructions from the IESO for energy and/or OR supply – causing other resources to not be dispatched, in addition to potentially setting very low LMPs.
  - An extreme circumstance from the example above could be LMPs approaching -$2,000/MWh (i.e., negative MMCP) and IESO still needing to curtail supply, therefore creating power system operation issues.

The above points regarding the potential for predatory pricing and price suppression within the IAM post MRP implementation are analogous to similar issues already being experienced within the Northeast U.S. Capacity Markets (i.e., NYISO, ISO-NE, and PJM).

While capacity is a different electricity product to energy and OR, the analogy holds when taking into account the structural differences between Ontario and these U.S. Capacity Markets. That is, if IESO were to administer a Capacity Market requiring all resources (i.e., contracted, rate-regulated, merchant) to participate, minimum offer pricing rules (MOPRs) and potential buy-side mitigation (BSM)[14] rules would be needed for the Capacity Market[15] to clear prices indicating system capacity needs and affording

[14] See https://www.nyiso.com/documents/20142/8363446/BSM-Overview.pdf/7b22b74e-c69e-dfa5-ec62-adbc23b6a4e4 for an overview of BSM rules within NYISO. The overarching rationale for NYISO's implementation of BSM rules is to mitigate market effects of MP conduct that could substantially distort competitive outcomes and to avoid unnecessary interference with competitive price signals. This rationale is in-line and consistent with the rationale in this submission regarding the need to mitigate for predatory pricing and price suppression within the IAM.

[15] While IESO plans to administer the first Capacity Auction (CA) in December 2020, IESO administered CAs differ in many aspects to the Capacity Markets in NYISO, ISO-NE, and PJM. One relevant difference, in context of this submission, is that CAs will not require

sufficient revenues for resources to continue helping to maintain Ontario's resource adequacy requirements. This would be the case because of the significant quantities of contracted or rate-regulated capacity in Ontario that could distort capacity-market clearing prices.

Therefore, without such a Capacity Market being planned for within the IAM, the impacts of the contracts and rate-regulated generators, as described above, need to be considered with the MRP design for the wholesale energy and OR markets, specifically within the market power mitigation framework.

The general issue of the impacts of 'out of market' mechanisms (e.g., contracts) within wholesale electricity markets has been subject to multiple orders from the U.S. Federal Energy Commission (FERC) to respective Independent System Operators (ISOs)/Regional Transmission Organizations (RTOs)[16]. In the FERC's June 29, 2018 order to PJM regarding applicable MOPRs within their Capacity Market[17], they stated that "We find, based on the record before us, that it has become necessary to address the price suppressive impact of resources receiving out-of-market support."[18]

It should be noted that none of the U.S. Capacity Markets started with the need for specific design features and rules, such as MOPRs and BSM, to address predatory pricing and capacity price suppression. Yet, these design features and rules had to be created to solve specific issues resulting from mainly needing to take into account contracted resources (e.g., generators).

Again, the same rationale is analogous and applicable to the need to address similar dynamics within the IAM, as contemplated under the MRP design – specifically through market power mitigation.

Clarity on Market Power Mitigation Roles and Responsibilities

The planned development and administration of the Conduct & Impact Test will introduce another level of market monitoring, oversight, surveillance, compliance, and mitigation of MPs. Further, considering the robust scope of the proposed Conduct & Impact Test, significant amounts of IESO and MP resources will be needed to fulfill all requirements and obligations that must be adhered to within this new market power mitigation framework.

The above points must be considered relative to existing statutes, rules, protocols, and processes already in place to govern the market surveillance and compliance regimes within the IAM. Therefore, the roles and responsibilities within existing areas of market surveillance and compliance, and the future market power mitigation framework, must be reviewed, clarified, and made transparent mainly between, OEB,

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participation of all capacity resources in Ontario. Therefore, contracted and rate-regulated generation will not participate in CAs. Within the NYISO, ISO-NE, and PJM Capacity Markets, all capacity resources participate – even if they have 'out of market' contracts or regulated rates. Therefore, MOPR and BSM rules have been implemented in these Capacity Markets, and are not being planned for within the CAs.

[16] See https://www.ferc.gov/news-events/news/commissioner-robert-f-powelson-concurrence-pjm-interconnection-capacity-market

[17] See https://cms.ferc.gov/sites/default/files/CalendarFiles/20180629212349-EL16-49-000.pdf

[18] Ibid., see p. 4

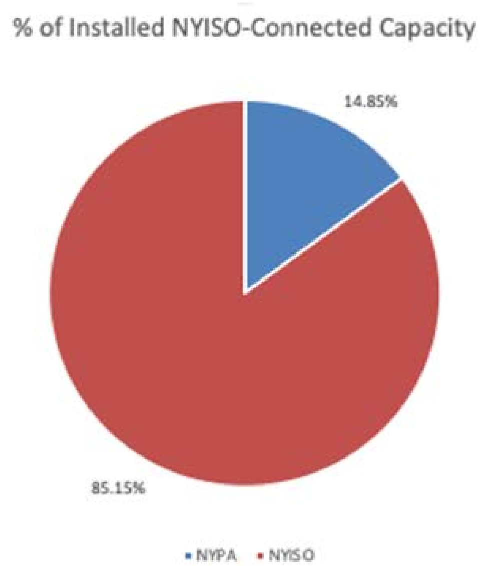
MSP, and IESO (i.e., Market Assessment and Compliance Division (MACD) business units and non-MACD business units). For example, in order to create clarity and transparency, MSP mandate, as set out in OEB Bylaw #3 and #5, should be reviewed and may need to be amended, same for the OEB-IESO Protocol[19].

At this time, it is not clear where the new market power mitigation framework through administration of the Conduct & Impact Test will reside within IESO, and then work alongside other IAM market surveillance and compliance activities and administration.

Supply Concentration Much Lower in Other Markets Compared to Ontario

Overall, no other wholesale electricity market in North America has such an extreme example of supply-side concentration by a single MP, as is the case with OPG within the IAM.

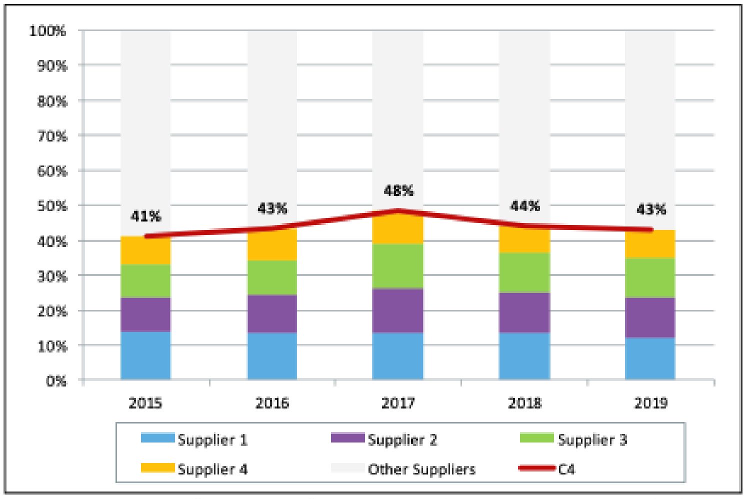
In both NYISO and ISO-NE – wholesale electricity markets that most resemble Ontario in terms of demand and supply mix – no MP generator has more than 20% of supply-side market share. As shown in the figure below, in NYISO, the largest supplier, the New York Power Authority (NYPA), owns and operates less than 15% of total supply capacity. This market share is much lower than OPG's approximate 50% share, as shown in the figure above under the section titled Ontario Power Generation Market Dominance. And the figure below that shows very low generator supply concentration in ISO-NE.



Source: Power Advisory, NYISO

[19] See https://www.oeb.ca/utility-performance-and-monitoring/electricity-market-surveillance, for the MSP mandate set out in OEB By-law #3 (most recently amended by By-law #5), and the OEB-IESO Protocol defining how IESO MACD (more specifically the Market Assessment Unit (MAU), where MAU is a business unit within MACD) will assist MSP.

Figure 3-47: Real-time System-wide Supply Shares of the Four Largest Firms



Note: The firms labeled "Supplier 1," "Supplier 2" and so on are not necessarily the same companies across all years; these are generic labels for the top four firms during a given year.

Source: ISO-NE Market Monitor Report

In PJM, which among other metrics, conducts a three-firm Pivotal Supplier Test as their market power mitigation framework (as opposed to a Conduct & Impact Test). As shown in the figure below, results from their Pivotal Supplier Test in the DAM show there was only one day where a single generator was considered a pivotal supplier with potential to exercise market power.

Table 3-88 Day-ahead market pivotal supplier frequency: 2019

Pivotal Supplier Rank	Days Singly Pivotal	Percent of Days	Days Jointly Pivotal with One Other Supplier	Percent of Days	Days Jointly Pivotal with Two Other Suppliers	Percent of Days
1	1	0.3%	33	9.0%	226	61.9%
2	0	0.0%	32	8.8%	217	59.5%
3	0	0.0%	27	7.4%	227	62.2%
4	0	0.0%	12	3.3%	188	51.5%
5	0	0.0%	12	3.3%	177	48.5%
6	0	0.0%	3	0.8%	79	21.6%
7	0	0.0%	1	0.3%	117	32.1%
8	0	0.0%	1	0.3%	99	27.1%
9	0	0.0%	1	0.3%	91	24.9%
10	0	0.0%	1	0.3%	80	21.9%

Source: PJM Market Monitor Report

Contrasting the above points from NYISO, ISO-NE, and PJM with the IAM, the potential for a single generator to exercise market power in Ontario is far greater and substantial than in any other wholesale market.

Specific Comments on ***Market Power Mitigation Detailed Design Issue 1.0***

Many of the general comments above relate to Chapter 2 in the draft *Market Power Mitigation Detailed Design Detailed Design Issue 1.0* regarding the scope of IESO's proposed market power mitigation framework (e.g., predatory pricing and price suppression could be in scope under Section 2.2 relating to mitigation in the future market) and why the scope should either be expanded within IESO's proposed market power mitigation framework or elsewhere within MRP.

The comments in the balance of this section regarding the draft *Market Power Mitigation Detailed Design Issue 1.0* focus on Chapter 3 (Detailed Functional Design).

Section 3.4.1 – The Mitigation Process

This section provides a useful overview of the proposed market power mitigation process. However, it is not a complete process, since steps for MPs to dispute IESO's application and results of market power mitigation needs to be included along with additional recourse MPs may exercise in addition to utilizing dispute mechanisms.

Section 3.4.2 – Conditions to Test for Mitigation for Price Impact, Section 3.4.3 – Conditions to Test for Mitigation for Make-Whole Payment Impact, and Section 3.12 Designation of Constrained Areas and Uncompetitive Interties

The Consortium is supportive of IESO use of the mitigation conditions listed under Tables 3-2 and 3-3 to determine whether to launch a Conduct & Impact Test towards determining whether to mitigate for market power. Because these mitigation conditions are the first steps toward potentially applying market power mitigation, they are extremely important in definition, derivation, application, and revisions.

Therefore, more details and information are needed regarding how IESO will determine these mitigation conditions and under what circumstances and frequency they may necessarily need to change. This will particularly be the case for mitigation conditions defining transmission constraints on the IESO-Controlled Grid (ICG). By and large, transmission constraints are dynamic and not static, as may power system conditions can change the impact of these constraints, for example: weather; energy flows; generation outages; transmission outages; changes in energy consumption; operating state of the ICG and application of IESO control actions; imports on specific interconnections; exports on specific interconnections; etc.

For example, take the Dynamic Constrained Area (DCA) mitigation conditions for local market power relating to energy. While local transmission constraints could be binding, the frequency and power system conditions that render the localized transmission constraint as binding can frequently change. Therefore, it will be important for MPs to understand how IESO plans to define DCAs and under what conditions may DCAs change and how frequently they may change.

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Consider a load pocket with a 200 MW daily average peak demand that is supplied by multiple transmission circuits and has a local 50 MW hydroelectric generator. If one of the transmission circuits is removed from service for a prolonged outage (i.e., a medium-term transmission outage), the transfer capability to supply the load pocket with the remaining transmission circuits would be reduced to 180 MW under normal weather conditions. The following points provide circumstances that could impact the DCA itself, and considerations for both IESO and potentially mitigated MPs.

- Under normal weather conditions, 20 MW of the 50 MW hydroelectric generator would be able to exercise market power in the load pocket while the remaining 30 MW would continue to compete globally in the IAM. This hydroelectric generator would need to manage their energy offers to reflect the potential market power mitigation application to part of the generation facility, assuming the entire capability of this generator is not subject to market power mitigation (i.e., only partially so).

- The DCA conditions could change throughout the medium-term transmission outage. For example, under extreme weather conditions assume that the transfer capability reduces to 150 MW. Under this situation, the whole 50 MW capacity of the hydroelectric generator would be able to exercise market power within the load pocket. This hydroelectric generator would need to understand the extreme weather attributes that impact the transmission circuits transfer capability (e.g., wind speed, dew point, ambient temperature, etc.) and how it would impact their energy offer strategy.

- Peak energy consumption in the load pocket could also influence DCA conditions. For example, assume that the load pocket consumption peaks at 210 MW instead of the expected 200 MW peak demand. Under normal weather conditions the 10 MW increase in local demand would increase the ability of any applicable supplying MP with a resource inside the load pocket to potentially exercise market power to 30 MW (i.e., 20 MW of transfer limitation plus 10 MW of above average load pocket demand). Applicable supplying MPs would need to understand how frequently the load pocket consumption pattern changes and what conditions might influence these changes. Further, the load pocket demand pattern will also be influenced by other not directly related impacts (e.g., economic activity, etc.). How load pattern expectations are incorporated into DCA conditions must be described to MPs, so they can understand whether their facility (e.g., generator) may be deemed with the ability to exercise market power and potentially be mitigated.

- Depending on the location of the load pocket, system conditions outside the load pocket could influence power load flow expectations that serve the load pocket. System losses, generation outages, and other transmission system outages could result in reduced expectations that global supply in Ontario could serve the load pocket, therefore increasing the likelihood of the transmission constraint becoming "binding".

- MPs would need to understand how each attribute influencing DCA conditions interacts with each other. For example, high winds could reduce the transfer capability but also reduce peak demand in the load pocket therefore mitigating the DCA condition. On the other hand, a heat wave could increase load pocket peak consumption and lower the transfer capability, therefore magnifying the DCA condition change.
- Finally, where a hydroelectric generator has been determined to be an energy limited resource, their offer prices may be relatively higher so as to reflect the value of limited energy. High offer prices can lead to market power mitigation without clear insight into how DCA conditions were determined.

Section 3.6 – Ex-Ante Mitigation for Economic Withholding

Reference level values are a key component to the application of the Conduct & Impact Test regarding potential mitigation of economic withholding through MP offer prices that are higher than applicable conduct thresholds and price impact thresholds.

Therefore, how reference levels will be determined and set, how long they are set for, when reference levels could change, and MP ability to dispute IESO's application of the Conduct & Impact Test including re-setting offer prices to respective reference levels, all need to be addressed well in advance of the planned MRP go-live date of 2023 and arguably before applicable amendments to the IESO Market Rules are finalized. The Consortium was pleased to learn during the July 24, 2020 IESO MRP update webinar presentation that specific stakeholder engagements are being planned to discuss reference levels and reference quantities.

The Consortium's comments on reference levels regarding renewable generators is provided in the applicable section later on in this submission.

Section 3.6.1.3 – Global Market Power Mitigation for Energy Price Impact

Regarding its definition under Section 3.3 in Table 3-1 on p. 16, global market power is defined as "Market power that can arise when competition is restricted because the *IESO* is unable to schedule incremental imports from other jurisdictions and *energy* and *operating reserve* supply conditions are limited".

It is not clear why IESO has chosen to define global market power contingent on incremental imports for energy and OR for a few reasons.

Even if Ontario's power system required incremental energy from imports to help maintain reliability of the ICG, this imported energy may not be able to meet Ontario's global power system needs due to some long-standing and frequent transmission constraints. For example, if energy is required in the northern zones and imported energy from New York and Michigan interconnections (located in the southern zones) are determined to be "incremental", then this incremental energy will most likely not meet the energy need within the northern zones due to congestion typically along the East-West transfer interface.

This could also be the case if energy is required in southern zones east of the Flow East Towards Toronto (FETT) transfer interface, where incremental energy from the Michigan interconnection or the New York interconnection at Niagara coming from west of FETT may not be able to meet this energy need due to congestion at FETT.

The fixed boundary condition limit for FETT is 5,000 MW. There are significant transmission-connected baseload generation that may flow eastward bound through FETT[20] – 6,300 MW of nuclear generation from the Bruce nuclear generation station and approximately 4,000 MW of renewable generation. While not baseload supply, there is also approximately 3,900 MW of additional gas-fired generation west of FETT. Therefore, FETT is limited in its ability to transfer energy into the Greater Toronto Area load. IESO's June 2020 Reliability Outlook[21] estimates average demand for zones west of FETT equals approximately 5,200 MW. The average demand for zones west of FETT and the FETT boundary condition approximately equal the installed baseload generation capacity in zones west of FETT (i.e., approximately 10,300 MW of generation). Adding gas-fired generation energy production west of FETT and energy imports through the Michigan and New York[22] interconnection at Niagara could exceed the FETT fixed boundary conditions. Therefore, incremental energy from the Michigan interconnection or the New York interconnection at Niagara may not be able to meet energy needs in the province due to congestion at FETT.

It is not clear why IESO has proposed to only include the New York-Ontario interconnection and the Michigan-Ontario interconnection as designated Global Market Power Reference Interties. Given the examples discussed above, if incremental energy and OR are to define Global Market Power Reference Interties, then all interconnections should be included within the proposed global market power mitigation framework – Quebec interconnections, Manitoba interconnection, and Minnesota interconnection. Also, for clarity, based on IESO's specification of "New York-Ontario *intertie*" on p. 25, it reads as though one of the two New York interconnections (i.e., Niagara and St. Lawrence) will be captured under Global Market Power Reference Interties. If so, which New York interconnection? If both New York interconnections are to be included, then this should be made clear.

On p. 26 under Condition 1 – Incremental Imports and under Condition 2 – Price, "shadow price" and "nodal prices" are used respectively. For clarity, do these terms simply equal applicable LMPs on the Ontario side of the respective interconnections? If so, "LMP" should be used for consistency as is the case with other draft MRP Detailed Design documents.

[20] Estimates of installed capacity are derived from the IESO's Active Contract Generation List (http://www.ieso.ca/-/media/Files/IESO/Document-Library/power-data/supply/IESO-Active-Contracted-Generation-List.xlsx)

[21] See http://www.ieso.ca/-/media/Files/IESO/Document-Library/planning-forecasts/reliability-outlook/ReliabilityOutlookTables_2020Jun.xls?la=en

[22] This does not refer to the St. Lawrence interconnection between Ontario and New York as it is east of FETT

In Table 3-9 on p. 26, dispatch data used as conduct thresholds referring to "start-up offer" and "speed no-load offer" do not make sense, as imports will not be permitted to submit three-part offers as dispatch data.

Regarding the need to administer market power mitigation for the Quebec interconnections, please see comments under *Section 3.12.5 – Designation of Uncompetitive Interties* later on in this submission.

Section 3.6.2.2 – Global Market Power Mitigation for Operating Reserve Price Impact

Comments above regarding *Section 3.6.1.3 – Global Market Power Mitigation for Energy Price Impact* also apply to Section 3.6.2.2.

Specifically, for OR, it is further not clear why IESO is proposing to use imports as the test for the exercise of global market power because OR is very rarely supplied to IAM through imports. This point is very relevant due to the Consortium's understanding that the only OR imports are supplied over Quebec interconnections and not over the remaining interconnections with New York, Michigan, Minnesota, or Manitoba (unless there is an extreme reliability need within Ontario and a neighbouring jurisdiction agrees to supply OR to meet this need, for example, as would be conducted under an IESO control action while the ICG has been declared to be in an emergency operating state).

Section 3.8.4 – Global Market Power for Make-Whole Payment Impact in the Energy Market

Comments above regarding *Section 3.6.1.3 – Global Market Power Mitigation for Energy Price Impact* and *Section 3.6.2.2 – Global Market Power Mitigation for Operating Reserve Price Impact* apply to Table 3-21 on p. 36 regarding imports not being permitted to submit three-part offers relating to make-whole payment conduct thresholds and import dispatch data.

Section 3.8.6 – Global Market Power for Make-Whole Payment Impact in the Operating Reserve Market

Comments above regarding *Section 3.6.1.3 – Global Market Power Mitigation for Energy Price Impact*, *Section 3.6.2.2 – Global Market Power Mitigation for Operating Reserve Price Impact*, and *Section 3.8.4 – Global Market Power for Make-Whole Payment Impact in the Energy Market* apply to this section.

Section 3.9 – Ex-Post Mitigation for Physical Withholding

While the Consortium accepts IESO's need to test for physical withholding, as discussed in the General Comments section above, there are Ontario-specific factors that should especially be considered regarding design and rules for assessment and mitigation of physical withholding.

OPG will be under some form of 'must-offer' supply obligation as a component of their generator license. Considering the significant market share OPG has – especially with hydroelectric and gas-fired generators that can supply sufficient amounts of all OR classes – the Consortium believes this will go a long way towards mitigating physical withholding within the IAM.

Additional to OPG's soon to be determined 'must-offer' supply obligation, the vast majority of the balance of non-OPG owned generators (i.e., Independent Power Producers (IPPs)) will remain under contracts well into the 2030s. Based on key contract provisions, including drivers and incentives to produce energy, these IPPs have many disincentives to physically withhold supply from the IAM. For example, the IPPs with Renewable Energy Supply (RES) I and II contracts are paid energy based on metered quantities of energy produced, and IPPs with Clean Energy Supply (CES) style contracts with 'deemed dispatch' settlement have strong contract incentives to offer energy into the IAM.

Therefore, IESO should consider these Ontario-specific factors towards developing a reasonable and workable physical withholding mitigation framework to be used from the outset of implementing MRP. As time goes on post MRP implementation, through assessments and 'lessons learned' from any physical withholding activities, and as contracts progressively expire into the 2030s, IESO should work with MPs and stakeholders in the future to evolve the physical withholding framework within the IAM.

Section 3.9.2 – Mitigation for Physical Withholding in the Energy Market

Starting in this section referring to the Resources Tested, Conduct Test, and Impact Test, and then in subsequent sections regarding IESO tests for physical withholding and other ex-ante market power mitigation tests, IESO has stated they "may" apply respective tests, whereas for the ex-ante tests for economic withholding IESO has stated they "will" apply respect tests. Why has IESO made this distinction? It can be interpreted that IESO's ex-ante application of respective tests appears to be subjective and therefore rendered to IESO's judgement when such tests are applied. Whether this is the case or not, more details will be needed regarding how IESO will make decisions to apply respective ex-post tests for the exercise of market power or not.

On p. 41, IESO refers to the need to perform ex-post market simulations of IAM impacts resulting from an MP that has be deemed to exercise physical withholding. Such market simulations are not trivial, and are time and resource consuming. Therefore, the Consortium recommends IESO to strive for reasonable and workable processes within any physical withholding mitigation framework, including application of ex-post market simulations.

3.12 Designation of Constrained Areas and Uncompetitive Interties

Building on above comments from *Section 3.4.2 – Conditions to Test for Mitigation for Price Impact* and *3.4.3 – Conditions to Test for Mitigation for Make-Whole Payment Impact*, IESO needs to establish clear and transparent processes to determine the designated constrained areas, including binding transmission constraints and load pockets, regarding definition, grid locations, magnitudes and impacts, and frequency of review and re-setting.

Determining when transmission constraints are "binding" and therefore determining load pockets are dynamic undertakings – power systems are in no way static.

As discussed in the above *Section 3.4.2 – Conditions to Test for Mitigation for Price Impact* and *Section 3.4.3 – Conditions to Test for Mitigation for Make-Whole Payment Impact*, for example, determining DCA conditions is a function of multiple variables influencing transmission constraints and load pockets. For example, extreme weather conditions can increase transmission constraints by lowering transmission transfer capability and increase energy consumption in load pockets beyond average peak energy demand expectations. The impact of dynamic system conditions (e.g., weather, temperature, outages, power load flows, etc.) are not uniform for different system components that determine a "binding" transmission constraint. Determining when a "binding" transmission constraint occurs requires monitoring and analysis on ever changing system conditions.

3.12.1 – Narrow Constrained Areas

As described in this section, IESO has defined Narrow Constrained Areas (NCAs) as "… areas where congestion is expected to be relatively frequent over a relatively long duration".

IESO should provide examples of NCAs, considering the amount of power system planning activities that have been undertaken and on-going regarding development of 18-month and 60-month Reliability Outlooks and 20-year Annual Planning Outlooks. This will help MPs envision what the NCAs may be, and therefore will be in better position to comment on the application of NCAs within IESO's proposed market power mitigation framework.

3.12.1.1 – Designated Criteria

It is reasonable for IESO to review NCAs on an annual basis. Details are needed regarding methodologies IESO will use to establish and re-establish NCAs. Further, if MPs do not agree with IESO established NCAs, a process for dispute and recourse needs to be defined.

This section states that "… *IESO* has an expectation that a load pocket will be constrained in more than 4% of the hours in the following year in either the day-ahead market of the *real-time market*, the *IESO* may designate such a load pocket as an NCA". Why has greater than 4% of the hours for the following year been used to determine an NCA load pocket?

4% of hours in a year is roughly two weeks. Forecast of future system conditions that could result in a "binding" transmission constraint is influenced by planning assumptions and methodologies. The difference between greater than 4% or less than 4% can easily be influenced by minor adjustments in the IESO approach (e.g., load forecast assumptions, load flow dispatch results, outage coordination). MPs must understand and have the ability to review and provide feedback on IESO planning assumptions and methodology. This will ensure MPs properly interpret the results and can clearly present clarification/corrections to the IESO.

3.12.2 – Dynamic Constrained Areas

As described in this section, IESO has defined DCAs as "… occasions when a transmission constraint binds or is expected to bind relatively frequently but not for a long enough duration to warrant the designation of an NCA. An example of this might be a transmission *outage* that results, or is expected to result, in increased congestion leading into a load pocket for periods of days. In such cases, these load pockets will be designated as a … DCA … for the duration the change in congestion conditions is expected to continue".

IESO needs to provide more details and clarity regarding what length of time or duration differentiates a binding constraint to be either an NCA or DCA. Further, IESO needs to provide more details and clarity regarding what magnitude of "increased congestion" will define the DCA load pocket.

The 4% of hours in a year used for the NCA designation is roughly two weeks, so DCA conditions would exist for less than that time. In many cases, the DCA designation could be applied due to unplanned outages on the power system (e.g., transmission line taken down during a storm). The constraint on the transmission system would have an uncertain timeline, that is, how long is it expected for the transmitter to repair the issues causing the outage. Treatment of unplanned outages that create DCA conditions as well as communication protocols about system conditions and reliability response time expectation to MPs is required. In addition, other dynamic system conditions (e.g., load pocket consumption, power load flow expectations, etc.) will influence whether DCA conditions will exist. Interaction of dynamic system conditions with unexpected outage events that create DCA conditions must be clearly described to MPs.

3.12.2.1 – Designation Criteria

This section states that "… *IESO* will determine the set of constrained areas of the transmission grid that meet any of the following conditions and may designate these as DCAs if:

- The load pocket is import constrained in more than 15% of hours in a continuous five-day period prior to the current period in either the day-ahead market or the *real-time market*; or
- The *IESO* identifies the prospective initiation of an *outage* or recurring conditions that previously caused a binding import constraint to a load pocket for at least 15% of hours in a continuous 5-day period in either the day-ahead market or the *real-time market*".

Why has greater than or equal to 15% of hours in a continuous five-day period been used to determine a DCA load pocket?

15% of hours over a continuous 5-day period is 18 hours, or just over 3.5 hours a day. The daily length of time would cover a typical afternoon peak period (e.g., 2pm to 6pm). Alternatively, the 18 hours would be applicable to a single planned outage for a transmission component (e.g., breaker replacement or transmission line energization). If those examples are the reasoning for IESO's selection of 15% of hours, IESO should clearly articulate that to MPs so they can understand future system conditions that could result in a DCA condition being declared.

3.12.3 – BCA Constraints

This section defines a Broad Constrained Areas (BCA) as a specific area relative to a reference location where a resource(s) is "dispatched up" by IESO where an applicable transmission constraint creates a load pocket that binds relatively infrequently. This section goes on to state that "… BCA exists any time one or more resources outside an NCA or a DCA are scheduled with a congestion component greater than $25/MWh".

IESO needs to provide more details and definition for determining BCAs. The proposed application of BCAs towards launching the Conduct & Impact Test will in part be triggered by IESO issuing dispatch instructions directing the resource (e.g., generator) to produce more energy than otherwise offered or was uneconomic for its supply based on its original offer. Therefore, if MPs are to be subject to market power mitigation resulting from following IESO's dispatch instructions where their resource happens to be located in an area coinciding with some form of transmission constraint, more details are required to properly comment on this aspect of market power mitigation.

3.12.5 – Designation of Uncompetitive Interties

This section states that "… *IESO* will designate *interties* where competition is restricted as uncompetitive *interties* and will apply mitigation measures at these uncompetitive *interties*", and "An *intertie* will be designated as uncompetitive when any one of the following conditions is true:

- An *intertie* where at least ninety percent of the day-ahead scheduled withdrawals or injections over that *intertie* in the ninety days prior to such an evaluation have been accounted for by one market control entity; or
- An *intertie* where the *IESO* finds grounds to believe that effective competition for the supply of imports or demand for exports is or is expected to be restricted."

Given the above proposed definition to determine whether interconnections are uncompetitive and therefore will be subject to market power mitigation, the Consortium suggests that given the number of radial interconnections between Quebec and Ontario that physically impede competition on these interconnections often rendering a sole MP with import or export transactions, than MPs as importers and/or exporters on these Quebec interconnections would appear to then be frequently under market power mitigation.

IESO needs to also account for how transmission reservations are made and who typically owns these reservations – especially on the Ontario-Quebec interconnections. Considering history, very few MPs have dominantly held the supply of transmission reservations at the Ontario-Quebec interconnections. This could be an indication of the potential to exercise market power.

Therefore, as stated earlier in this submission, all interconnections should therefore be accounted for under IESO's proposed global market power mitigation framework.

Further, IESO has an existing contract with Hydro-Quebec[23]. Does this contract create an uncompetitive interconnection(s) between Ontario and Quebec with Hydro-Quebec having market power on this interconnection(s)? If so, how will this be reconciled with the position of applying market power mitigation on uncompetitive interconnections?

3.13.1 – Reference Level Methodology for Financial Dispatch Data Parameters

IESO proposes to establish reference levels based on short-run marginal costs for a resource (e.g., generator) to supply energy or OR. The costs listed in this section to be included within the determination of facility-specific reference levels may be more easily established for resources with fuels that have market prices (e.g., natural gas) and prices for services (e.g., natural gas delivery and management).

During the IESO led MRP stakeholder engagement meetings throughout 2018 and 2019, using opportunity costs to establish reference levels for renewable generators was discussed, yet there is no mention of this in the draft *Market Power Mitigation Detailed Design Issue 1.0*. Therefore, has IESO disbanded establishing reference levels for renewable generators based on opportunity costs? If so, can the IESO explain why? If not, more details are needed towards guiding how opportunity costs will be established for facility-specific renewable generators within the draft *Market Power Mitigation Detailed Design Issue 1.0*.

3.13.1.1 – Process for Determining Cost-Based Reference Levels for Financial Dispatch Parameters

The Consortium agrees with IESO in establishing a process to initially define facility-specific reference levels, including processes to review and revise facility-specific reference levels.

Processes to initially establish, review, and revise reference levels needs to explicitly include processes for MPs to dispute IESO-determined reference levels. Dispute and any other MP recourse mechanisms and processes need to be included within the draft *Market Power Mitigation Detailed Design Issue 1.0*.

The Consortium was pleased to learn during the July 24, 2020 IESO MRP update webinar presentation that specific stakeholder engagements are being planned to discuss reference levels and reference quantities.

3.14.1 – Reference Quantity Methodology

To establish facility-specific reference quantities, IESO proposes to determine reference quantities for energy supply consistent with those used in Section 4 of IESO's Reliability Outlook Methodology.

[23] See https://www.fao-on.org/en/Blog/Publications/Electricity-Trade-0418 for available information on the existing IESO-Hydro-Quebec supply contract

The Consortium notes that based on many MP and stakeholder comments made to IESO in the past relating to power system planning methodologies regarding how resources are modeled relating to their capabilities to produce energy, more work needs to be done for IESO to improve their modeling of energy production capabilities from multiple resources.

For example, many hydroelectric generators have claimed that IESO has been consistently under estimating the energy production capabilities from many hydroelectric generators. Further, given the methodologies IESO uses within their power system plans to determine energy production capabilities from multiple resources, these methodologies do not appear to be as rigorous as the methodologies used in applicable U.S. wholesale electricity markets for purposes of qualifying resources for participation within respective Capacity Markets. Perhaps this has been the case because the methodologies IESO has been using within their power system planning has never needed to be used to fully or partially determine how resources must participate, be financially settled, or mitigated within the IAM. Therefore, the Consortium believes there is more work to be done to effectively determine facility-specific reference quantities.

3.14.2 – Initial Consultation and Frequency of Reference Quantity Review and *3.14.3 – Ongoing Consultation with Market Participants on Reference Quantity*

The Consortium agrees with IESO in establishing a process to initially define facility-specific reference quantities, including processes to review and revise facility-specific reference quantities.

As suggested for reference levels, processes to initially establish, review, and revise reference quantities needs to explicitly include processes for MPs to dispute IESO-determined reference levels. Dispute and any other MP recourse mechanisms and processes need to be included within the draft *Market Power Mitigation Detailed Design Issue 1.0*.

The Consortium was pleased to learn during the July 24, 2020 IESO MRP update webinar presentation that specific stakeholder engagements are being planned to discuss reference quantities and reference levels.

FINAL REMARKS

Reforms to Governance, Decision-Making, and Recourse within the IAM

The Consortium was pleased that the IESO had launched the Advisory Group on Governance and Decision-Making a few years ago, based on suggestions from MPs and stakeholders that the governance and decision-making framework within the IAM requires reform.

However, the Consortium's support was also contingent on the IESO's scope of review of the governance and decision-making framework within the IAM through the Advisory Group. That is, the IESO had determined that review of the roles and responsibilities of OEB regarding oversight over design changes within the IAM or amendments to the IESO Market Rules were out of scope. Also, out of scope was review of the IESO Board of Directors' authority to make rules and amend the IESO Market Rules. Considering these IESO imposed consultation parameters, the Consortium generally supported the recommendations and accompanying implementation plan for reforms[24] but believes further reforms will be needed – especially considering many of the design components within the proposed market power mitigation framework.

As identified in the Consortium's February 20, 2018 and December 1, 2017 submissions[25], the framework for governance, decision-making, and MP recourse within other wholesale electricity markets provides MPs and stakeholders with more robust input and/or decision-making authority regarding market design changes and rule amendments, as well as regulatory oversight. Regarding regulatory oversight, for all U.S. jurisdictions under FERC's authority[26], FERC has oversight regarding wholesale market rules or their equivalent[27]. Therefore, specifically for market power mitigation, all design changes and rule amendments are ultimately decided by FERC through transparent and inclusive regulatory proceedings.

Considering the impactful nature of market power mitigation, specifically its components that will drive economics within the IAM and for mitigated MPs, governance, decision-making, and MP recourse within the IAM needs to be revisited.

The Consortium will be happy to discuss the contents of this submission with you at a mutually convenient time.

Sincerely,

Jason Chee-Aloy
Managing Director
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[24] See Report and Implementation Plan at http://www.ieso.ca/Sector-Participants/Engagement-Initiatives/Engagements/Completed/IESO-Governance-and-Decision-Making

[25] Both submissions are located at http://www.ieso.ca/en/Market-Renewal/Stakeholder-Engagements/Market-Renewal-Working-Group

[26] FERC does not have any jurisdictional oversight of the Electricity Reliability Council of Texas (ERCOT) wholesale electricity market or power system

[27] Equivalency to market rules are embodied within specific Tariffs and/or Operating Agreements, but these are the rules that govern their respective wholesale electricity market

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