ONTARIO ENERGY BOARD

IN THE MATTER OF section 25(1) of the *Electricity Act, 1998*;

AND IN THE MATTER OF a Submission by the Independent Electricity System Operator to the Ontario Energy Board for the review of its proposed expenditure and revenue requirements for the fiscal year 2016 and the fees it proposes to charge during the fiscal year 2016.

SUBMISSIONS OF THE ASSOCIATION OF POWER PRODUCERS OF ONTARIO ("APPrO") AND HQ ENERGY MARKETING INC. ("HQEM")

Issues 2.1, 2.2 and 2.3:

2.1: Is the IESO's proposal to eliminate the OPA Usage Fee and to charge the proposed single IESO Usage Fee to all market participants (domestic and exporter customers) appropriate?

2.2: Is the methodology used to derive the proposed IESO Usage Fee of 1.13/MWh appropriate?

2.3: Is the proposed cost allocation study in support of the proposed IESO Usage Fee appropriate?

<u>Background and Summary of HQEM and APPrO's Position on Issues 2.1, 2.2 and 2.3</u>

1. By section 5(1), of the *Electricity Act, 1998*, the applicant is an amalgamation of "the predecessor Independent Electricity System Operator and the predecessor Ontario Power Authority". The latter entities will be referred to in these submissions as the "Predecessor IESO" and the "Predecessor OPA" (together, they are referred to as the "Predecessor Organizations").

2. Prior to the amalgamation, the Predecessor IESO charged a single usage fee to both domestic customers and export customers and the Predecessor OPA charged a usage fee to domestic customers.

3. The Predecessor IESO's usage fees has been charged to export customers following a settlement agreement which was approved by the Board in 2000.[1] As the Board has noted in several decisions, a Board approved settlement agreement does not have precedential effect.[2]

4. The Predecessor IESO's application in that case did not include a cost allocation study that addressed usage fees for export and domestic customers. Indeed, the Applicant's evidence in this case is that the Predecessor IESO had *never* prepared a cost allocation study to support the charge to export customers.[3]

5. The Predecessor OPA had applied to the Board to charge its usage fee to export customers for 2011; the Board refused that request. In doing so, it noted that the

[1] RP-1999-0049, transcript, pl. 67.
[2]See, for example, EB-2010-0142 (2011), EB-2007-0776 (2009).
[3] Exhibit I, Tab 2.1, Schedule 6.25 HQEM-APPrO IR 25 (ii) and (iii).

functions performed under the Predecessor OPA's statutory purposes were primarily for the benefit of domestic load customers. Those functions and purposes have been transferred to the IESO, but they have not fundamentally changed.

6. In the 2011 usage fees case, the Board also imposed conditions that the Predecessor OPA was to satisfy before requesting that its services be paid for by export customers, namely, that the OPA engage in relevant and substantive consultation and that any such proposal demonstrate a coherent rationale, supported by evidence. As submitted below, neither of those conditions were satisfied.

7. The only occasion where the Board has considered and approved the recovery of costs from export customers was in respect of export transmission customers in Hydro One's 2013-2014 rates case.[4] In that case, the Board held that export customers should not be charged the same rate as domestic customers because the latter received firm services while export customers received interruptible services. Importantly, the reason why the Board found that these services differed was because ***the IESO's rules*** provided a firm domestic service and an interruptible export service. In other words, it was the IESO's rules that differentiated treatment between domestic and export customers. The Board thus approved an export rate that was 34% of the domestic rate.[5]

8. Bringing all this together, the Board has never made a decision approving a single rate for domestic and export customers using Ontario's transmission network. The only time the Board did consider charging the same rate was at the request of the Predecessor OPA. The Board refused that request.

9. HQEM and APPrO submit that the Board should continue to refuse that request for two reasons. First, the IESO has failed to demonstrate that it has satisfied the concerns raised by the Board in the OPA's 2011 rates case. Second, the IESO continues to provide the differentiated services to domestic and import customers that led the Board to approve a reduced rate for export transmission customers.

[4] EB- 2012-0031 (June 6, 2013).

[5] When the Board approved the export transmission service rate in EB-2012-0031, the domestic rate was \$5.80/MWh and the approved export rate was \$2/MWh.

10. Unless and until the IESO comes forward with a more appropriate proposal for an export usage fee, HQEM and APPrO submit that an export usage fee that is 34% of the domestic usage fee is a more relevant and justifiable starting point than the current IESO usage fee. It is also aligned with the practices in other North American jurisdictions.[6]

11. In the alternative, if the Board does not follow the transmission rate example, then, at the very least, the IESO should not be collecting any amount for the OPA portion of the usage fee. The Board has set the preconditions that must be met by the OPA (now IESO) before recovering such amounts and those pre-conditions have not been satisfied. The Board can achieve this result by continuing the status quo of two different rates unless and until the IESO meets the conditions that the Board has laid out in the OPA's 2011 fees case, i.e., meaningful and substantive consultation with impacted customers and coherent and persuasive evidence in support of an export fee.

<u>The OPA's 2011 Fees Case (EB-2010-0279)</u>

12. The OPA proposed to recover its fees from export customers for its 2011 fees case. The Board refused that request in light of the following factors:

    i. The statutory purposes of the OPA in (then s. 25.2(1) of the *Electricity Act, 1998*) demonstrated that "expresses the OPA's fundamental responsibilities as being "for Ontario" and "in Ontario."[7]

    ii. The OPA did not undertake any meaningful or substantive consultation with stakeholders regarding its proposal. The Board stated that if the OPA intends to reintroduce its proposal, "the Board expects the OPA to have engaged the stakeholder community in a relevant and substantive manner."[8]

    iii. The proposed usage fee was not adequately supported by empirical evidence. The OPA proposal rested primarily on the IESO example, and "a rather cursory benefits analysis". The Board stated that, if the OPA intends to reintroduce its proposal, "it should be prepared to demonstrate a coherent rationale, quite possibly based on a cost allocation study…"[9]

[6] As Elenchus indicates in answer to HQEM-APPrO IR 23(iii) at Exhibit I, Tab 2.1, Schedule 6.23 , "no other North American system operator recovers its fees though a separate fee as opposed to embedding the recovery of its costs in the relevant transmission tariffs."

[7] EB-2010-0279, p. 16.

[8] EB-2010-0279, p. 17.

[9] EB-2010-0279, p. 17.

13. All of these factors remain the same and the Board's expectations have not been adequately addressed in the current application. Each will be addressed in turn.

The Predecessor OPA's Statutory Purposes Have not Changed

14. Apart from a reduction of the responsibilities granted to the Predecessor OPA, the statutory purposes of the Predecessor Organizations have not changed since the Board's decision in the OPA's 2011 fees case. Rather, they have been combined: Subsection 6(1) of the EA is no more than an aggregation of the objects of the Predecessor Organizations. With respect to the functions of the Predecessor OPA in particular, the following is a black-lined comparison of the relevant purposes in the 2011 fees case with the purposes in the current legislation:

- to forecast electricity demand and the adequacy and reliability of electricity resources for Ontario for the short term, medium term and long term;
- to conduct independent planning for electricity generation, demand management, conservation and transmission ~~and develop integrated power system plans for Ontario;~~
- to engage in activities in support of the goal of ensuring adequate, reliable and secure supply of resources in Ontario.
- to engage in activities to facilitate the diversification of sources of electricity supply by promoting the use of cleaner energy sources and technologies, including alternative energy sources and renewable energy sources;
- to ~~establish~~engage in activities in support of system-wide goals for the amount of electricity to be produced from ~~alternative energy sources and renewable~~different energy sources;
- to engage in activities that facilitate load management;
- to engage in activities that promote electricity conservation and the efficient use of electricity;
- to assist the ~~Ontario Energy~~ Board by facilitating stability in rates for certain types of consumers;
- to collect and ~~provide to the~~make public ~~and the Ontario Energy Board~~ information relating to the short term, medium term and long term electricity needs of Ontario and the adequacy and reliability of the integrated power system to meet those needs~~.~~; and

- to engage in such other objects as may be prescribed by the regulations.

15. As appears from the foregoing, the statutory purposes of the Predecessor OPA have not been expanded or changed to be more relevant to export customers.

16. Indeed, the only substantive change is the deletion of the objectives of “develop[ing] integrated power system plans for Ontario” and the “establish[ment]” of system wide resource goals. Both of those authorities have been transferred to the Government of Ontario.

17. Certainly, the transfer of planning and resource establishment authority to the Government of Ontario does not result in a more export oriented set of priorities for these functions. To the contrary, one can reasonably expect the Government of Ontario to be more responsive to domestic consumers than to exporters. This is reflected in the fact that, of the 102 Directives issued by the Government to the OPA/IESO, only 2 relate to export issues.[10]

The IESO did not Undertake Meaningful or Substantive consultation

18. The Board directed the Predecessor OPA to engage in meaningful and substantive consultation if it were to re-introduce its proposal to charge its usage fee to export customers. The IESO did not do this.

19. The IESO’s evidence is that it “has not specifically sought out stakeholders who are able to schedule exports” to evaluate its proposal.[11] Rather, the IESO pointed to three agenda items its Stakeholder Advisory Committee as satisfying the consultation requirement. These are described below.

20. First, at the March 5, 2015 SAC meeting, the IESO was asked how it “would manage OPA fees that were to be assigned only to domestic customers.” The only IESO comment on this point was that “the two predecessor organizations used different

[10] Exhibit I, Tab 2.1, Schedule 6.05 HQEM-APPrO IR 5 (iii).
[11] Exhibit I, Tab 2.1, Schedule 6.03 HQEM-APPrO 3 (iii).

methods for charging their fees, so management will have to decide which system to implement."[12] This is not consultation.

21. Second, at the August 13, 2015 SAC meeting, the IESO was asked about the usage fee and responded as follows: "Ms. Marshall [of the IESO] said this is an important area for intervenor engagement. Mr. Lyle [of the IESO] said a cost allocation study has been done and the IESO will engage with intervenors before filing with the OEB."[13]This is not consultation.

22. In fact, the IESO did not engage further with Intervenors before filing its application. Instead, approximately 5 months later, in January, 2016 it filed this application.

23. At the February 10, 2016 SAC meeting, after this application was filed, the IESO advised the SAC that the IESO had requested approval to charge an export fee. At that meeting, the IESO "acknowledged" that it "was unable to engage in as broad a stakeholder process as it would have liked prior to its revenue requirement case filing, which related to challenges in developing its first business plan. However, [Mr. Lyle] noted that there was some SAC discussion about the IESO's intention to charge a single fee."[14] Presumably, this "SAC discussion" was at the meetings on March 5 and August 13 as described above. This is not consultation.

24. Clearly by any measure the Board's requirements for meaningful and substantive consultation were not met.

The proposed Usage Fee is not Supported by Empirical Evidence

25. The Board rejected the OPA's previous proposal because it was not supported by empirical evidence. Indeed, it characterized the OPA evidence in that proceeding as "resting primarily on the IESO example."

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[12] Exhibit I, Tab 2.1, Schedule 1.0.1 Board Staff IR 1, linking IESO Stakeholder Advisory Committee, Meeting Notes, March 5, 201, pp. 9 and 3.
[13] Exhibit I, Tab 2.1, Schedule 1.0.1 Board Staff IR 1, linking IESO Stakeholder Advisory Committee, Meeting Notes, August 13, 2016, p. 6.
[14] Exhibit I, Tab 2.1, Schedule 1.0.1 Board Staff IR 1, linking IESO Stakeholder Advisory Committee, Meeting Notes, February 10, 2016, p. 7.

26. The evidence in this case is hardly more persuasive or coherent than what was filed in the previous case. In both cases, the OPA/IESO retained well known experts on cost allocation and rate design, but in both cases the work product of those experts leave much to be desired.

27. For these proceedings, in January, 2015, the IESO retained John Todd of Elenchus to prepare "expert evidence that would set out a proposal for the development of a rate design for the newly merged [IESO]. The proposed rate design (i.e., fee structure) would be consistent with, while replacing the existing IESO and OPA usage fees."[15]

28. At the outset, it is important to note that, although cost allocation and rate design are typically inextricably linked, in the interrogatory process, Elenchus' evidence is that its filed evidence is restricted to cost allocation and it is not providing evidence on appropriate rate design. According to Elenchus, "Rate design considerations are not addressed" in its evidence. [16] It therefore expressly did not address generally accepted regulatory principles, including appropriate revenue-to-cost ratios,[17] concerns respecting rate stability, rate shock,[18] mitigation, [19] and alternative fee designs.[20] As a result the evidence cannot be relied upon to support the proposed export usage fee's compliance with any of these principles.

29. When addressing the evidence, there are thus two separate issues: (i) the adequacy of the cost allocation evidence prepared by Elenchus; and (ii) the appropriateness of the IESO's proposed rate. Given how Elenchus and the IESO have parsed Elenchus' mandate to exclude rate design principles there is no expert evidence to support the appropriateness of the proposed rate.

The Adequacy of the Cost Allocation Evidence

30. With respect to the cost allocation, both the IESO and Mr. Todd acknowledged that the value of the cost allocation model filed in this case is severely limited because "slight

[15] Exhibit I, Tab 2.1, Schedule 6.14 HQEM-APPrO IR 14 (attachment).
[16] Exhibit I, Tab 2.1, Schedule 6.25 HQEM-APPrO IR 25(v).
[17] Exhibit I, Tab 2.1, Schedule 6.24 HQEM-APPrO IR 24(ii).
[18] Exhibit I, Tab 2.1, Schedule 6.25 HQEM-APPrO IR 25 (v).
[19] Exhibit I, Tab 2.1, Schedule 6.39 HQEM-APPrO IR 39.
[20] Exhibit I, Tab 2.3, Schedule 1.03, OEB Staff IR 3.

variations in exports as a percentage of total withdrawals have a disproportionate impact on the results from the model."

> "The IESO and Elenchus recognize that sensitivity to year-over-year changes in forecast energy volumes, including volumes that are driven primarily by the value of electricity in neighbouring markets, illustrates that the model used by Elenchus to produce the IESO's cost allocation study is not robust."[21]

31. The changes in resulting cost allocation calculations brought about by minor changes in data input are dramatic. In the course of this proceeding, the cost allocation model in the original evidence would have had exporters paying approximately 114% of their costs. An evidence update would have them pay 119% of their costs: the exporters' subsidy produced by this model thus increased by 36%. This dramatic change was driven by a 1% change in exports as a percentage of domestic volumes. When asked by Board staff what alternatives were considered in light of the weakness of the Elenchus model, the Applicant responded: "Given the timing of this realization, it was not possible for the IESO to develop alternatives to the standard cost allocation approach."[22]

32. In short, it is scarcely possible to base a Board approved rate on the model that undergirds the cost allocation evidence. Further, the IESO's explanation that the flaws in the methodology could not be repaired because it basically ran out of time does little to add confidence to using this information to support a Board approved usage fee.

33. The only reasonable approach in light of the weakness of this cost allocation evidence is for the IESO to go back and consider other cost allocation approaches in consultation with affected parties. As discussed above, despite the Board's specific direction to conduct consultation on this issue prior to the application, the IESO chose not to do so. This is unfortunate because an effective consultation may have identified these type of issues in advance. In this regard, the Board's observations in the 2011 fees case respecting program design are applicable here as well:

[21] Exhibit B, Tab 1, Schedule 2, p. 2 (emphasis added).
[22] Exhibit I, Tab 2.3, Schedule 1.03, OEB Staff IR 3.

> "the Board is of the view that **appropriate consultation can result in improvements** in program design, implementation and measurement **and is likely to increase the acceptance and credibility of OPA programs**."[23]

Rate Design

34. The rate design solution proposed by the IESO would have export customers pay approximately 119% of the costs used to serve them, thus providing a significant subsidy to domestic customers; its volatility by reference to small changes in data lead to concerns about lack of rate stability; it would result in rate increases of 41% to export customers by comparison to current usage fees.[24] All of these areas have been identified by the Board as inconsistent with good rate design.

35. As indicated, the IESO's expert, Elenchus, did not provide any evidence to defend these results or address these concerns because they were out of scope of its retainer with the IESO. However, Elenchus has, in previous proceedings before the Board, noted that over-recovery from one class of customers is inconsistent with just and reasonable rates:

> "We note that the OEB has explicitly endorsed a version of the Bonbright Principles, as stated in the Staff Discussion Paper for Recovery of Electricity Distribution Costs:
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> > *The Board identified three rate design principles for the purposes of this process. These principles encompass all of the "Bonbright attributes of a sound rate structure" identified in the March 2008 Staff Discussion Paper:*
> >
> > 1. *full cost recovery;*
> > 2. *fairness; and*
> > 3. *efficiency.*
>
> In our opinion, the Generally Accepted Regulatory Principles used as a touchstone for determining just and reasonable rates for transmitters and distributors are equally relevant for setting the ETS tariff in Ontario.
>
> Cost allocation is an important step in the overall rate making process and it is guided by the aforementioned Bonbright Principles. **The most essential**

[23] EB-2010-0279, p. 13 (emphasis added).

[24] The current usage fee is $.803 and the IESO's proposal is to raise this fee for exporters to $1.13. This 32.7 cent increase is a 41% increase to the usage fee for exporters.

element of these principles is that costs should be allocated to customer classes in a manner that reflects cost causality. The importance of this approach within the OEB's regulatory regime was clearly stated in the Report of the Board [in] EB-2007-0667 [the "OEB Rate Design Report"]:

> *The establishment of specific revenue requirements through cost causality determinations is a fundamental rate-making principle. Cost allocation is key to implementing that principle. Cost allocation policies reasonably allocate the costs of providing service to various classes of consumers and, as such, provide an important reference for establishing rates that are just and reasonable.*[25]"

36. As indicated, Elenchus does not purport to justify whether the subsidy created by its model is too high. According to Elenchus, that is a matter of rate design and therefore outside of the scope of its evidence.[26] Nevertheless the IESO refers to the OEB Rate Design Report as having established a revenue to cost ratio of 80% to 120% for some distribution customers. However, a few points should be noted.

37. First, the ranges identified by the Board should not be taken to stand for the proposition that rates within those ranges are appropriate. Rather, the Board's approved ranges arose in the context of transitioning distribution rates which were not developed with rate design principles in mind to a more principled basis. As the Board noted in the OEB Rate Design Report: "The general customer classifications have been in existence for many decades and the rate structures have been in place since the early 2000s."[27]

38. The Board thus characterized the use of ranges as "intended to be minimum requirements. To the extent that distributors can address influencing factors that are within their control (such as data quality), they should attempt to do so and to move revenue-to-cost ratios nearer to one."[28]

39. Thus, the establishment of these ranges were minimum and transitional requirements, leading to the goal of reducing subsidies which is an inherent feature of good rate

[25] Elenchus Report on Ontario Cost Allocation and Export Tariff Service, October 1, 2012 (EB-2012-0031), p. 4 (footnotes omitted; emphasis added).

[26] Exhibit I, Tab 2.1, Schedule 6.25 HQEM-APPrO IR 25(v).

[27] OEB Rate Design Report, p. 6.

[28] OEB Rate Design Report, p. 4.

making. They do not represent a *carte blanche* to permit cross subsidies among customers.

40. Other important rate making factors which are not addressed in the Elenchus evidence are rate stability and rate shock.

41. With respect to rate stability, the OEB Rate Design Report stated:[29]

> "A principle of rate making is that rate stability in most instances is desirable. Rates should not be constructed in a manner that leads to subsequent counter directional changes. The Board considers it appropriate to avoid premature movement of rates in circumstances where subsequent applications of the model or changes in circumstances could lead to a directionally different movement. Rate instability of this nature is confusing to consumers, frustrates their energy cost planning and undermines their confidence in the rate making process" (emphasis added).

42. In response to a request to comment on this statement, Elenchus stated, "The rate making principles identified in the question are important to rate design considerations; however, they are not a consideration in developing a cost allocation model."[30]

43. With respect to rate shock, the exporters' fees would increase 41% under the IESO's proposal.[31] The IESO's response: "The avoidance of rate shock is a rate making principle that is addressed through rate design, not cost allocation."[32] For the same reason, the IESO's evidence also did not address whether mitigating measures are called for.[33]

44. In summary, the IESO decided to not lead evidence to demonstrate that its proposed usage fee meets the requirements of sound rate design. As the IESO has the burden of demonstrating that its fees application should be approved by the Board, the IESO's failure to discharge its burden of demonstrating that its proposed usage fee meets the requirements of sound rate design is surprising and should lead to the IESO's proposal being dismissed.

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[29] At p. 6 (emphasis added)
[30] Exhibit I, Tab 2.1, Schedule 6.25 HQEM-APPrO IR 25(iv).
[31] Exhibit I, Tab 2., Schedule 3.0, BOMA IR 2.
[32] Exhibit I, Tab 2.1, Schedule 6.25 HQEM-APPrO IR 25(v).
[33] Exhibit I, Tab 2.1, Schedule 6.39 HQEM-APPrO IR 39.

<u>Export Transmission Services (EB- 2012-0031)</u>

45. The Board's treatment of rates for transmission services is particularly relevant for this application for at least four reasons.

46. First, the only time the Board has adjudicated upon export rates has been in the context of transmission rates. In that proceeding, the Board heard from three different experts in a "hot tub" format, where the experts were to provide assistance to the Board as opposed to advocating their client's interests.

47. That proceeding attracted a range of interests, including that of the IESO which, at that time, submitted that an export rate of zero "would best encourage the efficient operation of the wholesale market, specifically efficiency in the generation, transmission and sale of electricity."[34]

48. Second, the Board has relied upon IESO market rules to determine that transmission services are interruptible. The evidence in the transmission proceeding was that export service is interruptible while domestic service is firm. The Board's decision addressed this as conclusive:[35]

> "First, whether curtailments originate from generation issues or transmission issues, the Board agrees that export service does not receive the same priority as domestic service. **<u>The Board accepts that the market rules treat exporters more as an interruptible load.</u>** This difference in treatment related to generation capacity has consequences for the overall service, even if export transmission rights are technically as firm as domestic transmission rights. As a result, the Board finds that it may be appropriate for the export service to be viewed as a separate class."

49. The "market rules" that the Board referred to in that decision were the IESO interruptible protocols which interrupted exports before domestic load. The priority of service for domestic load over exporters remains unchanged since the Board considered this matter in EB-2012-0031.

50. More specifically, according to the IESO's evidence in that proceeding, Market Manual 7.4, Appendix A (version 25), "lists the actions taken in advance of and during the IESO

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[34] EB- 2012-0031, p. 6.
[35] EB- 2012-0031, p. 6.

controlled grid emergency operating state. The curtailment of exports is item #30 on this list and would be undertaken in advance of item #43, which is curtailing non-dispatchable load."[36] Similarly, Market Manual 7.1, Appendix B, filed in this proceeding, lists the emergency operating control actions in a similar priority: curtailment of exports is item #31 while curtailing non-dispatchable domestic load is item #44. In addition, in Market Manual 7.1, Appendix B.2, all exports are curtailed by Action # 9 while non-dispatchable domestic load is curtailed by Action #11.[37]

51. HQEM and APPrO note that pursuant to the capacity sharing agreement entered into between the IESO and HQEM and as set out in Market Manual 7, Part 7.1: System Operating Procedures, if Hydro Québec TransÉnergie has issued a reliability declaration to the IESO, the IESO is to support firm energy exports to Hydro Québec (via load curtailment on a pro-rata basis with Hydro Québec), up to the IESO capacity obligation.[38] It is important to note that any firm energy exports under the capacity sharing agreement only arise in the context of a reliability declaration. According to the IESO, as a general matter, a Reliability Declaration will occur when there is a shortfall in the market. If Hydro Québec TransÉnergie has not issued a reliability declaration, the usual IESO rules that provide priority service to domestic loads over exports apply. The result is that firm exports under the capacity sharing agreement have been non-existent (as they have been over the last five years).[39] Consequently, the capacity sharing agreement entered into between the IESO and HQEM does not change the fact that the IESO's rules provide priority service to domestic loads over exports.[40] Nor does the IESO's indication that it is in the process of developing a capacity export mechanism change the fact that currently, the IESO's rules provide priority service to domestic loads over exports.

[36] See EB-2012-0031, Ex. I, Tab 23, S. 6.02 HQ 2.

[37] See Market Manual 7.1, Exhibit I, Tab 2.1, Schedule 6.02 HQEM-APPrO IR 2.

[38] See Market Manual 7.1, Appendix B, page 51.

[39] See the IESO's answer to HQEM-APPrO IR 1.

[40] The same is true of a recent MOU relating to a generator exporting on a firm capacity basis to New York. HQEM and APPrO understand that this particular arrangement was entered into after the answers to IRs were submitted in this proceeding. In any event, as noted, firm energy exports under the MOU will only arise in the context of reliability or emergency, therefore this MOU does not change the fact that the IESO's rules provide priority service to domestic loads over exports.

52. In sum, in EB- 2012-0031 the Board found that the IESO's rules provided priority service to domestic loads over exports and this has not changed. The Board recognized that as a result of these rules providing priority for domestic loads, it would require a separate transmission rate for domestic loads and exports. The case for a separate, lower rate for exporters is stronger here because it is the IESO's usage fees which are being considered, not transmission rates, and yet the impact on export customers who are exposed to curtailment is identical to the impact identified by the Board in EB- 2012-0031.

53. Third, the IESO and the transmitters are inextricably linked. As the Board is aware, one of the key OEB licensing requirements of transmitters is to "enter into an agreement with the IESO that gives the IESO the authority to direct the operations of the licensee's transmission system."[41]Indeed, the IESO-controlled grid, which is under the operational responsibility of the IESO, is defined in the *Electricity Act, 1998* as "**the transmission systems** with respect to which, pursuant to agreements, the IESO has authority to direct operations."[42]

54. Applying this point to usage fees, it is worth noting that the integration of transmission and system operations for rates purposes is consistent with the treatment of system operator usage fees in American jurisdictions. According to the IESO's expert witness, "no other North American system operator recovers its fees though a separate fee as opposed to embedding the recovery of its costs in the relevant transmission tariffs."[43]

55. As a result, the Board's findings with respect to transmission rates should be applied to the IESO as well, namely, that the IESO provides a priority service to domestic customers over export customers and that different level of services should be reflected in a distinct export rate which is significantly lower than the rates charged to domestic customers.

[41] *Ontario Energy Board Act, 1998,* ss. 70(k).
[42] *Electricity Act, 1998*, s. 2(1) (emphasis added).
[43] See Elenchus answer to HQEM-APPrO IR 23(iii) at Exhibit I, Tab 2.1, Schedule 6.23 (HQEM-APPrO IR 23(iii)).

Remedy proposed

56. The Applicant has not demonstrated that it is appropriate for export customers to pay the same usage fee as domestic customers. The fact that the Predecessor IESO used to charge a single fee for both exports and domestic customers is not determinative or even persuasive. It reflects a historical compromise among intervenors, unsupported by any empirical evidence. Moreover, this compromise was not deliberated on and approved by the Board.

57. The only time where the Board did have evidence in relation to how much exporters should pay in a contested proceeding with respect to transmission rates, it found that the IESO provided lower priority service to export transmission customers and that those customers should therefore pay a lower rate, specifically, 34% of the amounts paid by domestic customers. This is a more relevant and justifiable starting point than the current IESO usage fee. It is also aligned with the practices in other North American jurisdictions.[44]

58. In the alternative, if the Board does not follow the transmission rate example, then, at the very least, the IESO should not be collecting any amount for the OPA portion of the usage fee. The Board has set the preconditions that must be met by the OPA before recovering such amounts and those pre-conditions have not been satisfied. The Board can achieve this result by continuing the status quo of two different rates unless and until the IESO meets the conditions that the Board has laid out in the OPA's 2011 fees case, i.e., coherent and persuasive evidence in support of an export fee and meaningful and substantive consultation with impacted customers.

Issues 2.4 and 2.5:

2.4 Is the IESO's proposal to charge the proposed single IESO Usage Fee from January 1, 2016 and to refund (or charge) market participants the difference between the 2016 single Usage Fee and the interim usage fees they paid, if any, based on their proportionate quantity of energy withdrawn, which may include scheduled exports and embedded generation, in 2016, appropriate?

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[44] As Elenchus indicates in answer to HQEM-APPrO IR 23(iii) at Exhibit I, Tab 2.1, Schedule 6.23 , "no other North American system operator recovers its fees though a separate fee as opposed to embedding the recovery of its costs in the relevant transmission tariffs."

2.5 What would be an appropriate effective date for the Usage Fee(s) approved in this proceeding?

Background and Summary of HQEM and APPrO's Position on Issues 2.4 and 2.5

59. The IESO has requested approval to charge or rebate to market participants the difference between the 2016 usage fees approved by the Board and the interim usage fees paid by market participants based on their proportionate quantity of energy withdrawn in 2016.[45]

60. Under the IESO's proposal, if the Board were to decide on December 1, 2016 to approve the usage fee as requested by the IESO, the IESO has indicated that export customers would be charged an additional $5.4 million on their bill following the Board's approval.[46] In other words, exporters would be charged $5.4 million for transactions undertaken in the past, namely transactions undertaken since January 1st, 2016.

61. The IESO has stated that it has not sought retroactive rates in this application.[47] HQEM and APPrO agree that legally speaking, when rates have been made interim as is the case in this proceeding, the Board may approve a rate change back to the date when the rates were made interim, so in that sense, the rates are not technically retroactive. This, however, is subject to the transitional legislation discussed in paragraphs 65 to 67 below.

62. Moreover, leaving technicalities aside, if the IESO's proposal is approved, export customers will be required to pay $5.4 million for transactions that have occurred since January 1, 2016 with no opportunity to recover those costs from their counter-parties. Moreover, it is not even possible to know whether all the transactions that occurred since January 1, 2016 would have occurred with a higher IESO usage fee in place. The Board has made it very clear that from a policy perspective, it is opposed to retroactive rates, including under circumstances where legally, the Board is permitted to order rates to apply back to the date of an interim order.

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[45] IESO Argument-in-Chief para 4, see also IESO Application at Exhibit B-1-1, page 6.
[46] See IESO's answer to HQEM-APPrO IR 44, Exhibit I, Tab 2.1, Schedule 6.44 HQEM-APPrO 44, page 1.
[47] See IESO's answer to HQEM-APPrO IR 44, Exhibit I, Tab 2.1, Schedule 6.44 HQEM-APPrO 44, page 1.

63. In addition, it is problematic that the IESO appears to believe that market participants should bear the consequences of the IESO's own delays in filing its business plan outside the timelines required by the *Electricity Act.*

64. Most importantly, subsection 25(10) of the *Electricity Act* does not permit the Board to allow any new usage fees to be backdated to a date prior to the Board's approval. This will be addressed immediately below.

Legislative Framework

The Transitional Legislation does not allow for an Application of any Newly-approved Usage Fee Backwards from the Date that the Board Approves any New Usage Fee:

65. Subsections 25(9) and (10) of the *Electricity Act* provide as follows:

> Transition, fees
>
> (9) Until the Board approves the proposed expenditure and revenue requirements for the IESO's first full or partial fiscal year that occurs after subsection 3 (1) of Schedule 7 to the Building Opportunity and Securing Our Future Act (Budget Measures), 2014 comes into force and the fees the IESO proposes to charge during that full or partial fiscal year, **the IESO shall continue to charge the fees that were approved by the Board and that applied to its predecessors immediately before subsection 3 (1) of Schedule 7 to the *Building Opportunity and Securing Our Future Act (Budget Measures), 2014* comes into force.**
>
> (10) For greater certainty, the Board's orders relating to the predecessors' expenditure and revenue requirements and **fees for their fiscal year that applied immediately before subsection 3 (1) of Schedule 7 to the Building Opportunity and Securing Our Future Act (Budget Measures), 2014 comes into force continue to be in effect until the Board approves the first expenditure and revenue requirement and fees for the IESO.** (Emphasis added)

66. Pursuant to subsections 25(9) and (10) of the *Electricity Act,* the usage fees for the Predecessor IESO and the Predecessor OPA are the usage fees that are to continue to apply until the Board approves the first expenditure and revenue requirement and fees for the IESO.

67. In other words, the legislation does not allow for an application of any newly-approved usage fee applying backwards from the date that the Board approves a new usage fee.

The IESO could have, Pursuant to the Applicable Legislative Provisions, Filed its Business Plan and Subsequent Fees Application at an Earlier Date – Market Participants Should not be Forced to Bear the Consequences of the IESO's Own Delays

Section 24(3) of the Electricity Act did not prevent the IESO from filing a business plan in 2015:

68. In answer to HQEM-APPrO IR 45, the IESO states as follows:

> The Building Opportunity and Securing Our Future Act, 2014, which merged the IESO and OPA, specifically dealt with the transitional year after the amalgamation. Section 24.(3) of the [Electricity Act] states that despite the normal legislated timelines, the IESO was to submit a business plan for the first full or partial year after amalgamation 30 days after the Minister requests a business plan. In 2015, the Minister did not request a business plan and so there was not an approved plan to allow the IESO to file a revenue requirement submission with the OEB. (Emphasis added)

69. HQEM and APPrO do not agree that in 2015, the IESO was required to wait for the Minister to request a business plan. Section 24(1) of the *Electricity Act* does not prevent the IESO from providing a business plan *prior to* the Minister's request for same. Section 24(4) of the *Electricity Act* states that the Minister shall only exercise his or her discretion to request that the IESO submit a business plan under subsection 24(3) where, in the Minister's opinion, there is insufficient time for the IESO to comply with its normal schedule as set out in Section 24(1). The IESO did not make any submissions regarding insufficient time to submit a business plan in 2015, nor did the IESO provide any other reason as to why it could not submit a business plan according to the usual timeframe (which is discussed below) in 2015. The IESO has therefore provided no valid reason as to why it could not submit a business plan in 2015. As a result, section 24(3) is inapplicable and the timing set out in section 24(1) (as discussed below) is applicable. There is no requirement in section 24(1) for the Minister to request that the IESO provide a business plan.

The IESO could have, and should have, filed its business plan in 2015 or earlier in 2016:

70. Section 24(1) of the *Electricity Act* states as follows:

> Business plan
>
> 24. (1) At least 120 days before the beginning of each fiscal year, the IESO shall submit its proposed business plan for the fiscal year to the Minister for approval. (Emphasis added)

71. Section 24(1) requires the IESO to submit its proposed business plan to the Minister for approval at least 120 days before the beginning of each fiscal year, i.e., filing in August, 2015 for a fiscal year starting in January, 2016 or filing in August 2016 for a fiscal year starting in 2017. However, the evidence is that the IESO did not even submit its business plan to the IESO until November 16, 2016[48] for a fiscal year starting in January 2016.

72. Therefore, the IESO submitted its business plan late by any standard. The regular legislated process required that the IESO submit its plan by August, 2016 at the latest for a fiscal year starting in 2017. The IESO's submission that it "submitted a business plan for 2016 in line with the regular legislated process" is not consistent with the IESO evidence that it submitted its business plan on November 16, 2016.

73. Knowing that it would seek approval for a new usage fee starting January 1, 2016, the IESO should have planned ahead and submitted its business plan to the Minister earlier in 2016 and in any event, by August 2016 at the latest. Instead, the IESO's failure to plan ahead and file its business plan in a timely manner caused the Minister's delay in approving the IESO's business plan. The IESO should not be able to point to the lack of Ministerial approval of its business plan as the reason for the delay in its rate application, because it is the IESO's own delay which caused the delay in the Minister's approval of its business plan.

[48] See Exhibit A-2-1, page 1 and Exhibit A-2-2, page 1.

In its November 2, 2016 letter to the Board filed in this proceeding, the IESO states that the IESO submitted its 2016 Business Plan in "September, 2016", but the IESO does not provide the day of the submission and in any event, the "September, 2016" date is not part of any of the evidence submitted by the IESO.

<u>The Board's Policy Against Retroactive Rate-Making</u>

74. In addition to the transitional legislation precluding the application of any newly-approved usage fees backwards from the Board's date of approval and in addition to the IESO's failure to submit its business plan (and therefore rate application) in a timely manner given the legislation and the date the IESO sought for rates to be effective, the Board's policy against retroactive rate-making should prevent the Board from allowing a new fee to apply back to January 1, 2016.

75. "The Board abhors retroactive ratemaking."[49] This is what the Board stated of itself in a decision in which it subsequently permitted a correction of an error.[50] The Board's policy is that it does not generally endorse retroactive rate-making. In Enbridge's 2001 rates case, the Board states as follows in regards to the timing of Enbridge's application and the retroactivity of rates:

> 2.2.7 The Board is also concerned with the timing of ECG's application. The Board notes that the Company was still filing sections of evidence in November 2000, well after the date that the Company requested for the implementation of new rates. While the Board attempts to process applications as quickly as possible, because of the complicated nature of major rates applications and quasi-judicial nature of the Board's mandate, the Board can only expedite the process to a certain extent. The Board expects that in the future the Company will file its application, along with supporting evidence, sufficiently in advance of the requested implementation date in order to provide time for the Board to understand the issues and conduct due diligence, and for the intervenors to respond.
>
> 2.2.8 <u>In addition, the Board is concerned about the retroactivity of rates. While the parties agreed in the Settlement Proposal that rates would be retroactive, and the Board has sanctioned that position by accepting the Settlement Proposal, the Board cautions the parties that, because retroactive rates do not give accurate price signals in the market and may result in inter-generational subsidization, the Board does not generally endorse retroactive rate-making.</u> In the future, the Board expects the Company to provide cogent evidence and rationale as to the reasons why rates should be retroactive.[51] (Emphasis added)

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[49] See EB-2004-0513 / 2006 LNONOEB 8, para. 55.

[50] The error was in the application of an unbundling methodology. The Board found that the correction of the error was not retroactive ratemaking. See EB-2004-0513 / 2006 LNONOEB 8, para. 55-57.

[51] RP-2000-0040, 2.2.7 and 2.2.8..

76. In the above-cited case, the reason that the Board was willing to accept retroactivity was that retroactivity had been agreed to by <u>all</u> parties in a settlement proposal.

77. No such settlement exists in this proceeding (apart from an agreement among domestic customers that export customers should pay them $5.4 of a $11.8 million dollar "rebate"[52]).

78. Similarly, in Enbridge's 2007 rates case, the Board discussed the issue of retroactivity to the date of an interim order:

> **Board Findings**
>
> 267 **<u>The prospect of retroactivity is always problematic for the Board.</u>** To be clear, having declared the Company's interim effective January 1, 2007, the effective date for the new rates i[s] not a legal issue in this case. The Company can in this case request and the Board can grant an effective date of January 1, 2007. **<u>Rather, the issue of retroactivity is one of rate impacts and customer acceptability. The Board has stated numerous times that it does not endorse retroactivity, regardless of how the monies are recovered.</u>** The Board has attempted to work with the utilities and other parties so that retroactivity can be avoided. Some progress was made in recent years but now that progress appears to have been stalled. [53] (Emphasis added)

79. The Board has made it clear that regardless of how retroactivity arises, it is a concern:

> "The Board is concerned with retroactivity, regardless of how it arises. Retroactivity is of particular concern when it involves cost reallocations among rate classes and rate redesign. "[54]

80. In the above-cited case, not allowing for retroactivity would have impacted the economic sustainability of the utility. In the current proceeding, this is not an issue. As mentioned above, the retroactive charge to exporters will fund part of a "rebate" for domestic customers.[55]

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[52] See IESO answer to HQEM-APPrO IR 45 (Exhibit I, Tab 2.1, Sch. 6.45).
[53] See EB-2006-0034 / 2007 LNONOEB 44, paras. 267.
[54] See section 6.0.2, OEB Decision dated December 20, 2004 in EB-2004-0253 (2004 LNONOEB 6).
[55] See IESO answer to HQEM-APPrO IR 45 (Exhibit I, Tab 2.1, Sch. 6.45).

Conclusions and Remedy Proposed on Issues 2.4 and 2.5

81. In sum, the practical effect of the IESO's proposal is to impose what the IESO has indicated will be approximately $5.4 million in retroactive fees on exporters. While this proposal is not illegal given that the Board may change rates back to the time an interim order was made, it is clearly inconsistent with the Board's policy and practice against retroactive rates. More importantly and as discussed above, subsections 25(9) and (10) of the *Electricity Act* preclude the application of any newly-approved usage fees backwards from the Board's date of approval.

82. Moreover, as shown above, the IESO could have and should have, pursuant to the applicable legislative provisions, planned ahead and filed its Business Plan and subsequent fees application at an earlier date. Market participants should not be forced to bear the consequences of the IESO's delays.

83. Consequently, any change to the IESO's usage fees should not be effective at any date prior to the Board's decision in this proceeding.

ALL OF WHICH IS RESPECTFULLY SUBMITTED

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