OEB STAFF INTERROGATORY 1

2.0 Usage Fee

2.1-Staff-1

INTERROGATORY

Reference: Exhibit B, Tab 1, Schedule 1 and OEB Decision and Order in EB-2010-0279, dated July 11, 2011, p. 17

In its Decision in EB-2010-0279, page 17, the OEB stated: "Should the OPA choose to re-introduce this approach now or in the future, the Board expects the OPA to have engaged the stakeholder community in a relevant and substantive manner and will require that evidence of this consultation be filed in conjunction with the associated revenue requirement and fees application."

a) Did the IESO engage the stakeholder community in the development of the single usage fee proposal? If the IESO consulted stakeholders, please provide a summary of feedback, if any and explain how it has been incorporated. If the IESO did not consult stakeholders, please explain why.

RESPONSE

a) The IESO is required under subsection 24. (1) of the *Electricity Act, 1998* to submit its proposed business plan to the Minister of Energy for approval on an annual basis. This approval was provided on December 9, 2015. Subsequently, the IESO did make presentations to the IESO's Stakeholder Advisory Committee ("SAC") on its proposal to seek one fee on February 10, 2016.

The IESO's SAC is a public forum that provides appointed stakeholder representatives with the opportunity to present advice and recommendations on matters directly to the IESO's Board of Directors and Leadership Team. Members of SAC represent consumers, generators, distributors/transmitters, related businesses/services and Ontario communities. Several of the SAC members also represent intervenor groups. A summary of the presentation to stakeholders and the comments received can be found in the meeting notes on pages 5 through 8 at the following link: http://www.ieso.ca/Documents/consult/sac/SAC-20160210-Meeting-Notes.pdf.

Previously, the IESO's proposal for one fee was also discussed at the March 5, 2015 SAC meeting (please see pages 3 and 9 of the minutes at the following link: http://www.ieso.ca/Documents/consult/sac/SAC-20150305-Minutes.pdf). It was also discussed at the August 13, 2015 SAC meeting. The notes for this discussion can be found on pages 6, 7, and 8 of the meeting minutes at the following link: http://www.ieso.ca/Documents/consult/sac/SAC-20150813-Meeting_Notes.pdf.

HQEM-APPRO INTERROGATORY 1

2.0 Usage Fee

Issue 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?

2.1-HQEM-APPrO-1

INTERROGATORY

Reference: General Interrogatory to IESO.

(i) Please confirm whether any of the generation capacity that has been or is currently planned, in operation, or in construction in Ontario has been exported as firm capacity to any neighbouring jurisdiction, tagged as such in NERC e-Tags, and possibly designated as an external network resource or an equivalent installed capacity designation by the external control area.

(ii) Please provide the yearly quantity of associated firm energy exports from the capacity described in (i) over the last 5 years (in MWh) and how those firm export quantities compare with the total export quantities.

RESPONSE

(i) There is currently no generation capacity in Ontario that is being exported as firm capacity to any neighbouring jurisdiction. Within Ontario, transmission service is provided once a transaction is economically scheduled. As such, trading participants do not have to obtain internal transmission service, unlike many other markets or non-market jurisdictions in the region.

While no specific generator has had their capacity exported, the IESO supports the capability as detailed below:

a. The IESO has a capacity sharing agreement with HQEM http://www.ieso.ca/Documents/corp/Summary-Capacity-Sharing-Agreement-Ontario-Quebec.pdf) which essentially creates the ability for HQEM to export up to 500 MW of firm capacity to Quebec from the Ontario market (as opposed to a single generator). As per the Quebec Capacity Sharing Agreement, each jurisdiction must ensure that any capacity committed to the receiving jurisdiction is subtracted from the sending jurisdiction's adequacy assessments; essentially that capacity becomes available as a firm transaction if called upon. While there is no requirement for the receiving jurisdiction to add the committed capacity to their assessments, the IESO cannot presume what HQEM includes in their adequacy calculation for Quebec.

b. As for planned export capacity, the IESO is in the process of developing a capacity export mechanism (http://www.ieso.ca/Pages/Participate/Stakeholder-Engagement/Capacity-Exports.aspx) whereby certain generators would be able to export, on a firm basis, capacity to an external jurisdiction. The extensive stakeholdering effort began in early 2015 and continues today.

(ii) There have been no firm capacity exports between Ontario and our neighbouring jurisdictions.

HQEM-APPRO INTERROGATORY 2

2.0 Usage Fee

Issue 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?

2.1-HQEM-APPrO-2

INTERROGATORY

Reference: General Interrogatory to IESO.

(i) Please provide all protocols and practices administered by the IESO with respect to the provision of export service and, in particular, those that address when export services (including wheel-through transactions) may be curtailed. The response should be inclusive of IESO's emergency operating practices when internal transmission constraints or resource adequacy issues require the curtailment of exports, wheel-through transactions or internal loads.

RESPONSE

The IESO does not believe this question relates to an approved issue in its 2016 Revenue Requirement Submission. However, to be helpful, the IESO has nonetheless provided information to the questions asked above.

Provision of export service:

All organizations wishing to export out of Ontario must be authorized as a market participant.

This process is administered by the IESO to ensure that an organization has met certain criteria to move energy into or out of Ontario. Some of the components required of an exporter include an NEB licence, obtaining business contacts, and providing the ability to meet prudential support obligations (prudential support mitigates the risk to the market of payment defaults).

- The participant authorization process is administered by the IESO. *Please refer to Market Manual 1.1* (http://www.ieso.ca/Documents/marketEntry/me_ParAut.pdf *for details on the Participant Authorization procedures.*

Participants must be able to schedule their export transactions in the Ontario market.

A participant must place a bid into the IESO administered market to purchase energy at the intertie. An export will be scheduled if the bid is economic and the transmission grid (i.e. the intertie and the IESO-controlled grid) can physically accommodate the transaction. Participants must also create a matching NERC tag.

For linked wheels, Participants must place both their bid and offer into the IESO Administered Market (IAM), and link the bid and offer through NERC tags in a specific format. *Please refer to Market Manual 4.2 (http://www.ieso.ca/Documents/marketOps/mo_DispatchDataRTM.pdf) for details on the submission of dispatch data in the real-time energy market.*

The IESO provides software tools, training, and ongoing assistance through the assignment of an account manager to assist participants with learning how to schedule exports into the market.

IESO coordinates with other control areas

The IESO coordinates with other control areas every hour, and conducts a reliability assessment before the import or export transaction is implemented.

Curtailment of exports and linked wheels:

All protocols and practices for curtailing exports are contained in Market Manual 4.3 (http://www.ieso.ca/Documents/marketOps/mo_RealTimeScheduling.pdf), Market Manual 7.1 Appendix B (http://www.ieso.ca/Documents/systemOps/so_SystemsOperations.pdf) (for curtailment of exports or internal load under emergency conditions), and Market Manual 7.2 section 4.4 (http://www.ieso.ca/Documents/systemOps/so_NearTermAssessReport.pdf) (for curtailment of linked wheels if a nuclear shutdown is imminent).

The IESO uses market mechanisms including hourly intertie schedules and 5 minute-dispatch instructions to Ontario resources to maintain reliability, and only intervenes when the dispatch systems are unaware of certain prevailing conditions (i.e. generator equipment restrictions). The curtailment of exports is just one control action available to the IESO to manage reliability. The IESO may initiate the curtailment of exports for one or more of the following reasons:

- An outage that impacts intertie export transfer capabilities;
- Adequacy issues;
    - If conditions change in real time and there are insufficient internal resources or ramping limitations of internal resources to solve the problem.
- To relieve an intertie scheduling limit exceedance (violation) when it is caused by:
    - An unplanned outage or de-rating, or
    - Another entity failing or curtailing a transaction.
- To resolve NERC Interconnection Reliability Operating Limit (IROL) exceedances where power flows are above acceptable limits;
- To protect critical flowgates (i.e. due to loop flow);
- To respect a Transmission Loading Relief (TLR) issued by another Reliability Coordinator; and
- To resolve an IESO and external control area energy deficiency.

Linked wheels will only be curtailed where the action will mitigate a limit violation, or expand transmission limits that will resolve reliability issues such as the imminent shutdown of nuclear generation and only when there are exports that can be scheduled to alleviate the situation.

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HQEM-APPRO INTERROGATORY 3

2.0 Usage Fee

Issue 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?

2.1-HQEM-APPrO-3

INTERROGATORY

Reference: General Interrogatory to IESO.

(i) Please explain how the aforementioned market mechanisms (including exports) and out-of-market mechanisms (including linked wheels curtailments) help alleviate or manage SBG conditions.

(ii) As regards the curtailment of linked wheels to alleviate SBG, when a curtailment occurs, are the impacted market participants financially compensated by the IESO? If yes, please detail the compensation(s).

(iii) Has the IESO consulted stakeholders who are able to schedule exports (for example through the Inter-Jurisdictional Trading Standing Committee) to evaluate the impact of the IESO fee increase to their level of activity? If yes, please file the minutes of the consultation. If not, why not?

(iv) What is the impact of the IESO's proposed fee on the annual amount of exports and what other mitigating measures will be necessary to address any reduction in exports?

RESPONSE

The IESO does not believe this question relates to an approved issue in its 2016 Revenue Requirement Submission. However, to be helpful, the IESO has nonetheless provided information to the questions asked above.

(i) Surplus Baseload Generation ("SBG") occurs whenever baseload generation exceeds Ontario demand. Anytime baseload generation is reduced, or Ontario demand or exports are increased, the effect will be to reduce SBG. As such a net export schedule increases market demand (which is Ontario demand plus export demand), therefore mitigating SBG.

SBG management is normally managed by automated market dispatch, whereby generation is shutdown or reduced to minimum levels, imports are minimized and exports are scheduled. There are times when operators must step in to manage SBG. The following represents a mix of automatic and manual actions to manage SBG:

- Hydroelectric generation can be dispatched down (to the degree allowed within limitations of safety, environment and applicable law) to reduce supply, therefore mitigating SBG.
- Grid connected renewable resources can be dispatched down to reduce supply, therefore mitigating SBG.
- Certain nuclear facilities can be manoeuvered using CSDV's (condenser steam dispatch valves) to reduce supply, thus mitigating SBG.
- Nuclear facilities can be shut down to reduce SBG.
- Import transactions may be curtailed to reduce supply, therefore helping SBG.

Linked wheel curtailment is only done to avoid a nuclear shutdown and only when the curtailment relieves tie-line congestion so additional Ontario sourced exports can be scheduled to prevent the nuclear shutdown.

(ii) No compensation is provided for linked-wheels curtailment.

(iii) The IESO has not specifically sought out stakeholders who are able to schedule exports, however, as more fully described in the IESO response to OEB Staff Interrogatory 1, at Exhibit I, Tab 2.1, Schedule 1.01, the IESO did make presentations to the IESO's Stakeholder Advisory Committee ("SAC"), which is a public forum that provides opportunities for both appointed stakeholder representatives and the general public to provide comments on matters directly to the IESO's Board of Directors and Leadership Team. In the SAC Terms of Reference, the Related Businesses/Services constituency lists "electricity traders/wholesalers" as one of the examples of which businesses fit into this category. Current membership in the Related Businesses/Services constituency is: Steve Baker, Union Gas; Jack Burkom, Brookfield; Paul Shervill, Rodan Energy.

(iv) The proposed change in IESO fee on export transaction is not expected to have a material impact on trading volumes given the industry's response to the increase in

Export Transmission Service ("ETS") rate in 2011. As can be seen in the table below (information available at http://www.ieso.ca/Pages/Media/Imports-and-Exports.aspx) since 2008 to 2015, export volumes have varied from a high of 22,618 GWh in 2015 to a low of 12,847 GWh in 2011. Note that export volumes increased the year after the ETS rate was increased by $1/MWh.

Year	Total (GWh)	
	Imports	Exports
April 2016	453	1522
March 2016	565	1,940
February 2016	509	1,990
January 2016	400	2,252
2015	5,764	22,618
2014	4,923	19,073
2013	4,880	18,309
2012	4,722	14,626
2011	3,913	12,847
2010	6,373	15,164
2009	4,844	15,104
2008	11,309	22,200
2007	7,198	12,286
2006	6,179	11,389
2005	10,941	10,181
2004	9,765	9,487
2003	10,432	6,261
2002	6,345	1,800

While the impact of one specific factor on overall export volumes is extremely difficult to predict, there are far more significant factors than the IESO fee or ETS rate that can impact intertie trading, including exports. The IESO believes export decisions are based on a variety of factors, many of which change on an hourly basis. Impactive variables include the hourly Ontario energy price, exchange rates, market clearing prices in neighbouring jurisdictions, the amount of surplus generation on the system, legislated requirements for clean resources, as well as longer-term macro level variables.

As noted above, export volumes vary based on many factors so mitigating measures are not required.

HQEM-APPRO INTERROGATORY 4

Issue 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-HQEM-APPrO-IR4

INTERROGATORY

Reference: General Interrogatory to IESO.

(i) Please confirm that in Ontario, entities that export power or perform linked wheels fall under the previous PSEs functional entity in the NERC Registration Process.

(ii) Please confirm PSEs are not subject to reliability audits by NPCC and/or provincial authorities in Ontario.

(iii) Please confirm the IESO does not incur any direct reliability-related costs as regards PSEs.

(iv) Please confirm that the quantity of electricity exported does not, in itself, have an impact on reliability or Ontario's NERC responsibilities?

RESPONSE

(i) Yes, the IESO can confirm that in Ontario, entities that export power or perform linked wheels fall under the definition of the previous Purchasing-Selling Entities ("PSEs") functional entity in the NERC Registration Process.

(ii) Yes, confirmed. Entities that perform PSE functions (Marketers) in Ontario are not subject to NERC standard audits. As the classes of market participants in the Ontario market rules do not directly align with the NERC functional model entity types, the IESO, in consultation with stakeholders, mapped the Ontario market participant classes to the NERC Functional Model Entities and by extension, mapped the NERC Reliability Standard and NPCC criteria requirements to market participant classes.

a. A list of Ontario market participant classes cross-referenced to NERC Functional Model Entity types that are subject to compliance with NERC reliability standards is published on the IESO website and also shown below:

Ontario Market Participant Class	NERC Functional Model Entity
Generator	Generator Owner Generator Operator
Transmitter	Transmission Owner

(iii) No, this is incorrect. While a PSE entity is no longer mapped to NERC standards, the potential for and results of import/export transactions must be assessed and managed by the IESO on a regular and routine basis in order to maintain reliability and to maintain the IESO's compliance with NERC reliability standards. Examples of reliability-related costs that the IESO incurs regarding PSE's include, but are not limited to:

a. planning and operational studies, internal and with our neighbours, to determine transmission (internal and intertie) capacity needed to accommodate interchange transactions,
b. coordination of interchange transactions with other reliability coordinators,
c. management of real-time interchange transactions as it pertains to maintaining Ontario reliability (ensuring internal transmission, tie-lines and neighbouring areas remain within acceptable limits),
d. the maintenance and utilization of software tools used in the interchange process,
e. conducting stakeholder consultations with participants who import and export energy, and
f. providing ongoing support to importers/exporters as to their participation in the market and use of tools.

(iv) No, this is incorrect. Electricity that is exported out of Ontario has a direct impact on reliability. NERC reliability standards require the IESO to coordinate all interchange transactions with other reliability coordinators, make an internal and tie-line reliability assessment for every export transaction that is submitted to the IESO markets, and take action if exports (or imports) must be curtailed to maintain reliability either internal to Ontario or in a neighbouring jurisdiction. The larger the export quantity the larger the reliability impact, hence there is an administrative burden related to assessments of system reliability mandated by NERC standards. In addition, imports and exports play a key role in helping to balance the power system. The IESO has a NERC obligation to maintain our Area Control Error ("ACE"), which is a measure of how well the system is balanced. ACE is a function of imports, exports, Ontario generation, Ontario load, and system frequency. Large changes in exports require the IESO to respond in an equally significant manner to ensure the system remains balanced.

HQEM-APPRO INTERROGATORY 5

2.0 Usage Fee

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?

2.1-HQEM-APPrO-5

INTERROGATORY

Reference: Exhibit B Tab 1, Schedule 1, p.4.

(i) Please confirm that, according to the terms of reference, the IESO's Stakeholder Advisory Committee is made up of the following constituencies:

"3.1. Committee to consist of 12-18 members representing each of the following five categories:

- Persons representing the constituency of generators of electricity

  Examples of representatives in this constituency might include generation by gas, nuclear, wind, solar, hydro-electric

- Persons representing the constituency of consumers of electricity

  Examples of representatives in this constituency might include residential, embedded retail/industrial, directly connected industrial

- Persons representing the constituency of transmitters and distributors with at least one member representing transmitters

- Persons representing related businesses and services

  Examples of representatives in this constituency might include electricity traders/wholesalers, aggregators, innovation, research, smart grid, gas utility, conservation-related services

- Persons representing Ontario communities

Examples of representatives in this constituency might include municipalities, aboriginal, environmental, academia

At its discretion, the Board may appoint one or more ad hoc members for specified terms."

(ii) Please advise of any SAC members that have been appointed to specifically represent the interests of exporters with specific reference to the terms of their appointment.

(iii) Please advise how many directives the Minister of Energy has provided to the OPA and the IESO in their history. Please advise of which of these directives specifically was aimed at benefitting exports.

RESPONSE

(i) and (ii)

IESO SAC members represent the following constituencies: Generators, Distributors/Transmitters, Consumers, Ontario Communities and Related Businesses/Services. In the SAC Terms of Reference, the Related Businesses/Services constituency lists "electricity traders/wholesalers" as one of the examples of which businesses fit into this category. Current membership in the Related Businesses/Services constituency is: Steve Baker, Union Gas; Jack Burkom, Brookfield; Paul Shervill, Rodan Energy.

All SAC members were appointed by the IESO Board of Directors in March 2015 for a two-year term. http://www.ieso.ca/Documents/Ministerial-Directives/MC-2015-904-Outgoing-IESO-Letter-of-Direction-1.pdf Membership will be staggered so as to provide continuity to the Committee. Members can serve up to six consecutive years.

(iii) A total of 101 directions have been issued by the Minister to the former OPA and to the IESO. With respect to the request to advise as to which of these directives specifically are aimed at benefitting exports, the IESO is not in a position to interpret the Minister of Energy's aim behind these directions. As described in (please see the response to Energy Probe Interrogatory 10 c), at Exhibit I, Tab 2, Schedule 5.10, the work carried out by the IESO creates an interdependent relationship between domestic customers and exporters, and it is not possible to clearly separate out the benefits of this work for one group versus the other. The IESO does note that two of the directions do require the IESO to enter into contractual agreements for electricity supply with a neighbouring jurisdiction and these are described below:

- Non-Utility Generator Projects, Combined Heat and Power Standard Offer Program 2.0, Chaudière Falls Hydroelectric Generation and Whitesand First Nation Biomass Cogeneration (http://www.ieso.ca/Documents/Ministerial-Directives/2051214-Directive-NUG_CHPSOP_ChaudiereFalls_WhitesandFirstNation.pdf), issued on December 14, 2015: requires the IESO to enter into negotiations with Hydro Ottawa Holding Inc. or a subsidiary for power purchase agreements for supply from the company's Gatineau and Hull facilities.

- Procurements, issued on April 22, 2015 (http://www.ieso.ca/Documents/Ministerial-Directives/MC-2015-904-Outgoing-IESO-Letter-of-Direction-1.pdf): requires the IESO to negotiate and enter into a seasonal capacity sharing agreement with HQ Energy Marketing Inc.

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HQEM-APPRO INTERROGATORY 6

2.0 Usage Fee

Issue 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?

2.1-HQEM-APPrO-6

INTERROGATORY

Reference: Exhibit A-2-2, page 6 of 20

(i) Can the IESO comment on how its mandate and the departmental budgets as described in Elenchus' cost allocation study might change with the passing of Bill 135?

(ii) Does the IESO believe that its revenue requirement submissions going forward will materially differ from the 2016 revenue requirement submission due to the implications of Bill 135?

(iii) How will the relevance of Elenchus' evidence submitted by the IESO be affected with the passing of Bill 135?

RESPONSE

(i) The passing of Bill 135 modified the IESO's formal role in long-term planning from that of leading an Integrated Power System Plan to providing a technical report and an implementation plan as part of the Long Term Energy Plan ("LTEP"). Although the IESO's formalized role in long-term planning has changed, planning activities have always been performed by the IESO (and the OPA from which the current organisation is derived) as part of regular business. Whether or not a formal product has been provided publicly, planning information has been well utilized throughout the sector, including as input into other products such as regional plans, evidence in hearings before the OEB, and government policy. The passage of Bill 135 has also created a potential role for the IESO in undertaking the procurement of transmission systems. Although this will result in new responsibilities for the IESO, and government expectations are not currently well known, the IESO is not expecting the passage of Bill 135 to impact its departmental budgets or headcount for either the procurement or planning groups at this time. The IESO did recognize this as a potential risk to its business plan on page 9 of Exhibit B-1-1.

(ii) As described in part i) above, the IESO does not, at this time, foresee a change in its future revenue requirement submissions due to the passage of Bill 135, however impacts are not well known at this time.

(iii) As described in part i) and ii) above, the IESO does not, at this time, foresee a change in its future revenue requirement submissions due to the passage of Bill 135, and so there would be no impact on Elenchus' evidence.

HQEM-APPRO INTERROGATORY 7

Issue 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-HQEM-APPrO-7

INTERROGATORY

Reference: Exhibit B-1-1, Attachment 3, page 10, lines 2 – 4

(i) Please produce the terms of reference that the IESO provided to Elenchus and all other materials respecting the scope of the Elenchus study;

(ii) What sources did Elenchus use to identify "standard regulatory cost allocation principles and practices"? Please provide the authors and titles of work used for this assignment.

RESPONSE

(i) The terms of reference were set out in the Quotation Memo dated January 24, 2015 provided by Elenchus to the IESO and provided in the IESO's response to HQEM-APPRO Interrogatory 14, at Exhibit I, Tab 2.1, Schedule 6.14.

(ii) A primary reference for standard regulatory cost allocation principle and practices is National Association of Regulatory Utility Commissioners (January 1992) Electric Utility Cost Allocation Manual. This document is referenced in the Elenchus report at footnote 9. In addition, Elenchus' involvement in cost allocation reviews in numerous Canadian jurisdictions has provided Elenchus with direct hands-on familiarity with the cost allocation practices of companies and regulators across Canada, as well as the evidence other experts have filed as cost allocation evidence in these jurisdictions.

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HQEM-APPRO INTERROGATORY 8

Issue 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-HQEM-APPrO-IR8

INTERROGATORY

Reference: In EB-2012-0031, OEB Decision and Order dated June 6, 2013 regarding 2013 Export Transmission Service Rates states at page 6

(i) Does the IESO still hold the same opinion that exports are beneficial to the system, the province and the market?

(ii) Can the IESO clarify if its opinion in EB-2012-0031, specifically that the ETS charge should have been reduced to zero, was based on the notion that if faced with higher costs, exporters may no longer see the Ontario market as an economic place to do business i.e. schedule trades?

(iii) Can the IESO confirm if it is still of the opinion that increasing costs for exporters could in effect diminish the benefits that were highlighted by the IESO in EB-2012-0031?

(iv) Does the IESO agree that, all things being equal, as charges to exporters increase, the price at which they can economically purchase energy from the Ontario market to export falls? If so, does the IESO agree that the Global Adjustment costs may rise if wholesale prices are further depressed?

RESPONSE

(i) Yes.

(ii) The CRA study showed exports were inelastic to increasing the tariff; that is, there was very little impact on exports as a result of an increased tariff within the range examined. On the basis that none of the tariffs considered at the time would have a material impact on reliability, we were supportive of eliminating the tariff because it was the option that best promoted the efficient operation of the wholesale market, specifically, efficiency in the generation, sale, and transmission of electricity. The IESO position was not because increasing the tariff could result in exporters no longer seeing the Ontario market as an economic place to do business.

(iii) In carrying out the ETS study, CRA applied economic models that took certain price and non-price factors into account to provide the analytics necessary for the Board (and parties) to make an informed determination, but they inherently could not account for all future uncertainties. The IESO cannot extrapolate the findings of the CRA study to the IESO fee proposal, so the IESO is not in a position to "confirm" its opinion based on the CRA study. That said, as described in the response to HQEM-APPRO Interrogatory 3, at Exhibit I, Tab 2.1, Schedule 6.03, export volumes increased the year after the ETS rate was increased (in 2011). This is consistent with the finding of the CRA study regarding the inelasticity of export volumes to price increases within a range and that the benefits of exports are unlikely to be largely eroded as a result of price increases in that range.

(iv) All things being equal, as charges to exporters increase, the price at which exporters can purchase energy from the Ontario market to export may fall. As well, the Global Adjustment may rise if wholesale prices are further depressed. However, materiality is a consideration. As described in part (iii) above, CRA's study found that export volumes were inelastic within a range. The response to OEB Staff Interrogatory 4 at Exhibit I, Tab 2.4, Schedule 1.04, illustrates that exporters would pay roughly an additional $6 million with the IESO's proposed fee – approximately 2% of the amount paid by exporters to purchase the commodity in Ontario. While it is reasonable to assume that the increased IESO fee would be an even smaller percentage of exporter's sale price in other jurisdictions, the IESO does not have access to this information. The IESO believes export decisions are based on a variety of factors, many of which change on an hourly basis. The impact of one specific factor on overall export volumes is extremely difficult to predict. Impactive variables include the hourly Ontario energy price, exchange rates, market clearing prices in neighbouring jurisdictions, the amount of surplus generation on the system, legislated requirements for clean resources, as well as longer-term macro level variables.

HQEM-APPRO INTERROGATORY 9

Issue 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?

HQEM-APPrO-IR9

INTERROGATORY

Reference: Elenchus' May 17, 2013 report titled, "Review of Cost Allocation Policy for Unmetered Loads (EB-2012-0383)" prepared for the Ontario Energy Board, pages 5-6 and section 5

Elenchus Request:

(i) Can Elenchus confirm which cost allocation study would affect a larger group of customers both by number of customers and by energy exchanged – the unmetered loads study or the IESO 2016 study?

(ii) Can Elenchus comment on the length of time involved in producing the May 2013 report – including the facilitation of working group discussions? How does that compare to the time involved in producing the 2016 report? When discussing time involved, please identify both the elapsed time from the signing of the engagement letter to the delivery of the final report, as well as the total person-hours involved in each engagement.

(iii) Was sensitivity analysis as described in section 5 of the May 2013 cost allocation study referenced above performed in the 2016 cost allocation study for the IESO? If not, why not; if so, please provide the sensitivity analyses used in this study.

(iv) Did Elenchus recommend that the IESO provide establish a working group as part of this process? If not, why not; if so, please provide the request and all related correspondence.

(v) In accordance with Elenchus' comments regarding the involvement of stakeholders on page 6 of its May 2013 report – can Elenchus justify this departure from "good utility practice" in the IESO cost allocation study?

IESO Request:

(vi) Please confirm that stakeholder sessions were not held as a part of developing the IESO cost allocation study.

(vii) Can the IESO confirm – in relation to Elenchus response to question a) above that the volume of export transactions in Ontario is generally greater than the volume or capacity of unmetered loads? If so, please advise why consultations were not held as part of the scope of work for the cost allocation study done by Elenchus?

(viii) Please advise why a working group was not established as a part of the cost allocation study undertaken by Elenchus for the IESO's 2016 revenue requirement submission?

<u>RESPONSE</u>

(i) Technically, no customer is affected by a cost allocation study. Any customer impacts are determined by rate design decisions. Customer impacts result only when class revenue to cost ratios fall outside the Board-approved range, or rate changes that are not across-the-board adjustments are implemented for any other reason. It would appear intuitively that based on the count of customers that would have their bills directly affected, the number of IESO customers is far smaller than the number of customers of Ontario distributors. The energy exchanged might be larger in the case of the IESO, which would include both the domestic load and exports; however, this conclusion would depend on the view taken of embedded generation. Assuming the intent of the question is to identify the number of customers that are potentially affected by a cost allocation study either directly or indirectly, then, by definition all end users of electricity in Ontario are potentially affected by both studies. Given that the total revenue requirement is fixed in a cost allocation study, any impact is likely to result in changes to the costs allocated to all classes. Arguably there may be a few extra-provincial IESO customers that are affected by the IESO study that would not be affected by the unmetered load study.

(ii) Based on Elenchus' records, the duration of the work related to the May 2013 report for the OEB which initiated the stakeholder process was roughly 7months. An additional 10 months were required to complete the process. The billable hours totaled about 180. The IESO project commenced at the beginning of February 2015. The billable hours have totaled about 110 to the end of June 2016.

(iii) The sensitivity analysis as described in section 5 of the May 2013 cost allocation study referenced in the question was not performed in the 2016 cost allocation study for the IESO. The purpose of the sensitivity analysis for the 2013 study was to examine the impact of the policy on a sample of the distributors that would be required to implement the policy. No comparable sensitivity analysis would be appropriate or feasible in the case of the IESO study since the cost allocation of only one entity is impacted.

(iv) Elenchus did not recommend that the IESO establish a working group as part of this process. It was the understanding of Elenchus that the IESO's Stakeholder Advisory Committee ("SAC") is the forum for dealing with issues, including cost allocation and rate design. John Todd did participate in a SAC meeting on February 10, 2016 during which stakeholders provided comments to the IESO.

(v) Given the role of the IESO's SAC, Elenchus does not accept that there was a departure from good utility practice.

(vi) Please see response to OEB Staff Interrogatory 1, at Exhibit I, Tab 2.1, Schedule 1.01.

(vii) The IESO does not have information on the volume or capacity of unmetered loads to be able to provide a comparison with export transactions in Ontario.

(viii) A specific working group was not seen as required as the IESO has a long-standing SAC which has regular public meetings where anyone is free to attend and provide comments. Please also refer to OEB Staff Interrogatory 1.

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HQEM-APPRO INTERROGATORY 10

Issue 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-HQEM-APPrO-IR10

INTERROGATORY

Reference: Exhibit B-1-1, Attachment 3, page 22, "Operations Change Initiatives" lines 2-6

(i) Can the IESO clarify which of the capital projects listed on page 18 of its submission directly benefit or were caused by export customers?

(ii) Can the IESO offer the number of capital projects that it has undertaken over the last 3-5 years caused by, or for the direct benefit of export customers?

(iii) Can the IESO confirm that the Operations Change Initiatives department exists to facilitate the implementation of its Capital Plans/Projects?

(iv) If there have not been any recent capital projects caused by or for the direct benefit of the export class can the IESO or Elenchus offer comment as to why the Operations Change Initiatives budget has been allocated to exports, specifically in proportion to energy (TWh)?

(v) Going forward, given that Bill 135 gives full directive power over the IESO to the Ministry – how will the IESO as an administration control what capital plan/projects it undertakes in the future?

RESPONSE

(i) In general, the work of the IESO is influenced and performed equally for the benefit of both domestic and export customers as described in Exhibit B-1-2 and in response to Energy Probe Interrogatory 10, at Exhibit I, Tab 2, Schedule 5.10. All stakeholders benefit from a properly functioning electricity system, which is the responsibility of the IESO. Therefore, it is the IESO's belief that the projects listed on page 18 of its submission benefit both domestic and export customers.

(ii) The projects undertaken over the last 3-5 years largely cover infrastructure and application replacements, enhancements, upgrades and refreshes. Capital projects adding new functions over the same period include:

- Demand Response Auction
- Renewable Integration Initiative
- IESO Simulator
- Enhanced day-Ahead Commitment
- On Line Limits Development
- Energy Modelling

All of the above we believe benefit both domestic and export customers.

(iii) Yes, the Operations Change Initiatives department facilitates the implementation of Capital Plans/Projects for the Market and System Operations Business Unit.

(iv) Not applicable – see response to (ii) above.

(v) Directive powers do not eliminate management discretion. The IESO will continue to manage its business and determine how activities will be performed, overseen by an independent Board of Directors. As described in the IESO's response to AMPCO Interrogatory 15 at Exhibit I, Tab1.5, Schedule 2.15, the IESO's ongoing capital project prioritization process takes into account whether a project is related to a directed activity as one of the factors to determine its rank.

HQEM-APPRO INTERROGATORY 11

Issue 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-HQEM-APPrO-IR11

INTERROGATORY

Reference: Exhibit A-2-2, page 15 of 20, Appendix 1: Corporate Performance Measures.

(i) Were any of the established CPMs designed to ensure firm export or wheel through capability persists in Ontario? In other words, is the existence of firm export capability a measure of success or good performance for the IESO as a company?

RESPONSE

The IESO does not have an established CPM on intertie transactions or wheel through capability. While these market functions are enabled in the Market Rules, given the broad reach of the IESO's activities in the sector, the IESO develops CPMs by considering new, strategic and/or key operational areas of focus.

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HQEM-APPRO INTERROGATORY 12

Issue 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-HQEM-APPrO-IR12

INTERROGATORY

Reference: Exhibit B-1-1 and the OEB Order on the OPA 2011 Expenditure and Revenue Requirement Filing ("OEB Previous Order").

(i) Please file the evidence requested by the Board in the OEB Previous Order or otherwise that the IESO relies upon to support the allegation that it has met this requirement.

(ii) Please indicate precisely what consultations were held with stakeholders and when regarding the proposed fee, what the comments were received from stakeholders, and how the IESO incorporated this feedback into its proposal.

RESPONSE

(i) and (ii) Please see the response to OEB Staff Interrogatory 1, at Exhibit I, Tab 2.1, Schedule 1.01.

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HQEM-APPRO INTERROGATORY 13

Issue 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-HQEM-APPrO-IR13

INTERROGATORY

Reference: Exhibit B-1-1, section 2.3, page 9, lines 25-28

(i) Please describe how export customers receive incremental benefit from the restructured IESO role compared to the benefit they received under the predecessor IESO's role.

(ii) Please confirm that all functions previously exercised by the OPA are now exercised by the IESO. Please advise how the functions exercised previously by the OPA have, since the merger, benefitted exporters.

RESPONSE

(i) Please see the response to Energy Probe Interrogatory 10 c), Exhibit I, Tab 2, Schedule 5.10 for a discussion on how the work of the merged IESO benefits both domestic and export customers.

A direct comparison between the activities of the former organizations with the current organization is not valid due to amalgamation and the resulting integration of work activities. As noted in Exhibit B-1-1, it is increasingly difficult to separate out the costs and benefits of various functions of the IESO for certain customer classes. As an example, the IESO is working on an initiative to allow generators in Ontario to export their capacity to neighbouring jurisdictions. This initiative is benefiting from the former OPA's capacity procurement and planning experience, and the former IESO's knowledge of operating constraints on the system and markets.

(ii) All of the objects of the former OPA in the *Electricity Act, 1998* were merged with the IESO's objects as part of the amalgamation of the two organizations, however, as described in part i) above, these activities within the IESO cannot be directly compared to the activities of the former organizations.

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HQEM-APPRO INTERROGATORY 14

Issue 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-HQEM-APPrO-IR14

INTERROGATORY

Reference: Exhibit B, Tab 1, Schedule 1, page 11, lines 2-11

(i) Can Elenchus clarify what is meant by "somewhat non-standard"?

(ii) If the revenue-to-cost ratios calculated may not be as indicative of a true causal relationship as can be achieved in the typical utility cost model, why it is appropriate to use a zone of reasonableness that was linked to a typical utility cost model?

(iii) Can Elenchus clarify how it was determined that the best indicator available for allocating costs was that which was a manner consistent with the IESO's existing MWh based Usage fee?

(iv) Can Elenchus confirm what the scope of work was as described in its engagement letter with the IESO? Was exploring alternate fee designs

RESPONSE

(i) The words "somewhat non-standard" appear in the Elenchus Report at page 11, line 6. The words "this approach" in the sentence refer to the approach outlined in the preceding paragraphs, page 10, line 1 to page 11, line 5. The essence of the observation that the methodology that has been adopted is "somewhat non-standard" appears at page 10, lines 4-8: "In conducting this work, Elenchus has observed that the IESO's costs that are recovered through its Usage Fee consist largely of costs that would be treated as operational overhead or administrative and general (A&G) costs in the cost allocation models that are typically used by regulated electric utilities for their rate setting processes." The point being made is that the nature of the IESO's costs is quite different from the bulk of the costs of an electricity transmitter, an electricity distributor or an integrated electric utility. For example, the causal relationship between the capacity-related costs of a transmission line and customer demand is far more obvious than the causal relationship between the essentially administrative costs incurred by the IESO and the use that is made of the IESO-administered market by customer classes or individual customers. In the absence of a physical cost causality driver equivalent to demand (i.e., kW demand "causes" the need for capacity) or energy (i.e., kWh "causes" the need for energy), the allocators rely much more heavily on assigning costs in an equitable manner than through a physical or engineering relationship. The absence of engineering underpinnings to the causal relationship is the primary basis of the comment by Elenchus that the model is "somewhat non-standard". Additional non-standard features include the absence of a rate base and cost of capital in the IESO's revenue requirement and the absence of non-trivial customer related costs such as customer service, customer meters, etc.

(ii) Elenchus has not asserted that "it is appropriate to use a zone of reasonableness that was linked to a typical utility cost model." The Elenchus evidence states only that "if the OEB were to adopt an R/C ratio range of 80% to 120% for the IESO's usage fee, it would follow that …" (page 15, lines 16-17) In the absence of an OEB approved zone of reasonableness (revenue-to-cost ratio range) for the IESO, Elenchus used the most common OEB approved range for regulated electricity entities for purposes of illustrating the methodology that Elenchus considers appropriate for making a determination about customer classification (one or two classes) based on allocated costs. Zones of reasonableness are generally a matter of the judgment of regulators as there is no generally accepted quantitative methodology for determining an appropriate zone of reasonableness. The selection of an appropriate R/C ratio range is a matter that is appropriately addressed as part of rate design, not cost allocation.

(iii) As Appendix A to the Elenchus evidence shows, a variety of allocators are used in the model developed by Elenchus. One of the allocators used is TWh, which is used for costs for which a volumetric allocator appeared appropriate. There are no IESO costs that appear to be "caused" by demand, as would be common for a transmission company or distributor. Energy (TWh) appears to be a more appropriate volumetric allocator than a demand-related allocator such as TW.

(iv) The scope of work is described in the attached quotation memo.

Memorandum

elenchus

To: **Megan Filey and Adrian Pye, IESO**

From: **John Todd**

Date: **24 January 2015**

Re: **Quotation – Rate Design Evidence on Fees for the Merged IESO and OPA**

This memo provides a description of the proposed approach and fees for preparing expert evidence that would set out a proposal for the development of a rate design for the newly merged Independent Electricity System Operator ("IESO") and Ontario Power Authority ("OPA"). The proposed rate design (i.e., fee structure) would be consistent with, while replacing the existing IESO and OPA fees. The level of the fees would be sufficient for the merged entity to recover its OEB-approved revenue requirement.

The current IESO fees were approved in OEB Decision EB-2013-0381 dated 22 May 2013. The current OPA fees were approved in OEB Decision EB-2013-0326 dated 6 November 2014. Two previous OEB decisions dated 8 July 2011 and 10 August 2011 (Decision EB-2010-0279) address the issue of whether the OPA usage fee should be charged to export customers as proposed by the OPA.

The 8 July 2011 decision states at page 17:

> *Third, the Board agrees with the submissions of parties that the proposed fee has not been supported by empirical evidence. The OPA proposal rests primarily on the IESO example, and a rather cursory benefits analysis. The extension of fees to market participants should generally be conducted on a firm empirical and principled basis. There is no such basis in the evidence before the Board. In this case, if the OPA intends to reintroduce this approach in this or a future expenditure and revenue requirement and fees case, it should be prepared to demonstrate a coherent rationale, quite possibly based on an allocation study, as suggested by Mr. Todd from Elenchus.*

As a result of the merger of the IESO and the OPA, it will be appropriate to integrate the fees that were charged by the former agencies into a single fee schedule. To the extent that the terms and conditions of the existing IESO and OPA fees are either completely consistent or completely distinct, the new fee structure may require nothing more than combining the existing fee schedules. However, where the current terms and conditions differ, as in the case of the applicability of the current IESO and OPA usage fees to different types of market participants, careful consideration should be given to the appropriate design of the fee to be charged by the newly merged entity.

In light of the Board's comments quoted above, it may be appropriate to develop a cost allocation model that would provide a basis for establishing separate cost-based usage fees that would be applicable to in-province and export customers.

EVIDENCE ADDRESSING THE INTEGRATION OF THE CURRENT IESO AND OPA FEES

The engagement would involve the following four tasks:

1. **Assess consistency of the current IESO and OPA fees:** Conduct a detailed review of the existing IESO and OPA fees in the context of the future integrated structure and operations of the IESO. The purpose of this review will be to identify which of the existing fees should be retained as distinct charges, which fees should be merged, and which fees require a redesign. In particular, to the extent that there are existing IESO and OPA fees that are collected on the same basis, they could be replaced with a single IESO fee. Existing OPA fees that have no equivalent IESO fee at this time might be appropriately replaced with a new and equivalent IESO fee. Particular attention will be given to the appropriateness of replacing the existing IESO and OPA usage fees with a single new IESO usage fee in light of the differences in the terms and conditions (and underlying cost causality rationale for their applicability to different categories of customers). Consideration will also be given to the extent to which other transmission charges (e.g., for export transmission service) are relevant considerations in the design of future IESO usage and other fees.

2. **Cost allocation:** Assuming the proposed future integrated IESO usage fees result in the explicit (or implicit) recovery of costs previously recovered through the OPA usage fee, it will be appropriate to examine the cost causality basis for the usage fee as it applies to export and in-province customers, as per Decision EB-2010-0279. An analysis of the appropriate classification of customers and the causal costs associated with each potential distinct "class" of customers will be conducted in order to provide a "coherent rationale" for the application of the usage fee to the different classes of customers, as directed by the OEB in Decision EB-2010-0279, page 17. It is anticipated that a cost allocation model can be developed that functionalizes and classifies the integrated IESO's costs (revenue requirement) and allocates the costs to defined customer classes in a manner that reflects the principle of cost causality.

3. **Prepare expert evidence:** Expert evidence will be prepared that is suitable for filing as part of a future IESO fees application. The evidence will recommend a rate design that has a "firm empirical and principled basis" and will explain the analytic basis (cost allocation methodology) for the proposed rate design.

4. **Application/hearing support:** Assistance will be provided throughout the hearing process as required by the IESO. In particular, this support will include, to the extent requested by the IESO, responding to information requests, participating in technical conferences and settlement processes, appearing at the hearing and assisting with argument.

FEES

My current standard hourly rate is $400 per hour excluding GST. Professional fees will be invoiced monthly on the basis of actual time incurred. No out-of-pocket expenses are anticipated.

The estimated fees for the tasks outlined above are as follows:

Task #1:	10 hours	$ 4,000
Task #2:	25 hours	$10,000
Task #3:	15 hours	$ 6,000
Task #4:	To be determined	

Task #4 does not have a fees estimate since the time required for the hearing process is not within my control and is highly variable. Ideally, the recommendations that are made will be not controversial and the extent of support required will be minimal.

Subject to IESO approval on a case-by-case basis, I may utilize other Elenchus staff with significant experience in cost allocation methodologies and models to assist with analysis. In particular, Michael Roger and Andrew Frank may provide assistance with the development of a cost allocation model. Their time will substitute for my time and will be managed within the budget figure provided above.

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HQEM-APPRO INTERROGATORY 15

Issue 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-HQEM-APPrO-IR15

INTERROGATORY

Reference: Elenchus' October 22, 2015 report titled "New Brunswick Power Customer Cost Allocation Study Review" prepared on behalf of New Brunswick Power, the Executive Summary lines 16-20.

(i) Did Elenchus establish a "Reference Model" for the IESO's cost allocation study so that specific changes could be compared to the reference model? If so, please produce it. If not, why not?

(ii) Why weren't iterations of the model and its resulting revenue-to-cost ratios included in the cost allocation study as IESO evidence?

RESPONSE

(i) Elenchus typically uses the previously approved model as a Reference Model. This was done for the review of the NB Power Customer Cost Allocation Study. In the case of the IESO cost allocation work there was no previously approved model to use as a Reference Model. Elenchus is not aware of any logical alternative to use as a reference model for the IESO.

(ii) The only earlier iteration of the Elenchus model with its resulting revenue-to-cost ratios was filed with the IESO's original evidence on January 19, 2016. That earlier iteration was based on the IESO's 2015 financial information. The only other working versions of the IESO model were incomplete versions that were prepared in parallel with Elenchus requesting and receiving the more detailed information that was required to complete the model.

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HQEM-APPRO INTERROGATORY 16

Issue 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-HQEM-APPrO-IR16

INTERROGATORY

Reference: Elenchus' October 22, 2015 report titled "New Brunswick Power Customer Cost Allocation Study Review" prepared on behalf of New Brunswick Power, section 2.2 "Stakeholder Engagement Process" lines 18-25

(i) Did Elenchus recommend the importance of recognizing and allowing for stakeholder concern to the IESO? If yes, please produce the recommendation and all correspondence respecting the recommendation. If not, please explain why stakeholders were not involved in the IESO cost allocation study.

RESPONSE

(i) Elenchus did not recommend a stakeholder consultations process to the IESO. The IESO has a long-standing Stakeholder Advisory Committee ("SAC"), which serves that purpose for all matters. Mr. Todd appreciated the opportunity to hear the comments of stakeholders by participating in the SAC meeting on February 10, 2016. That meeting included an opportunity for stakeholders to comment on the Elenchus model that was filed with the IESO's original evidence on January 19, 2016.

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HQEM-APPRO INTERROGATORY 17

Issue 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-HQEM-APPrO-IR17

INTERROGATORY

Reference: Elenchus' October 22, 2015 report titled "New Brunswick Power Customer Cost Allocation Study Review" prepared on behalf of New Brunswick Power, section 3, lines 17-26

(i) Please produce its work-plan or scope of work for the New Brunswick cost allocation study and its work-plan or scope of work on the cost allocation study done for the IESO?

(ii) Can Elenchus compare the total number of pages and the total number of exhibits in the New Brunswick report and the IESO report?

(iii) Did Elenchus consider any of the other criteria that it describes on page 5 of its report as sometimes being used in establishing a cost allocation study methodology in the IESO case (i.e. Benefit derived from asset utilization; Consistency with government policy, e.g. conservation; Simplicity; and Acceptability)? If so please explain how and what criteria was ultimately decided on.

RESPONSE

(i) The NB Power review was undertaken in response to an Order of the New Brunswick Energy and Utilities Board ("EUB``) dated 9 April 2015 in Matter No. 271 (please see Attachment 1 to this exhibit). As directed by that Order, a work plan was filed on May 15, 2015 as Exhibit NBP7.01 (please see Attachment 2 to this exhibit). With respect to the IESO scope of work, please see the response to HQEM-APPrO Interrogatory 14(iv), at Exhibit I, Tab 2.1, Schedule 6.14.

(ii) The final Elenchus report was filed with the EUB in Matter No. 271 as Exhibit NBP 9.02 Appendix A. That report, including the five appendices specifically addressing the five studies that the EUB directed NB Power to complete by October 30, 2015, was 101 pages in length. The IESO report, including appendices was 41 pages in total.

(iii) In developing the methodology used for the IESO cost allocation model, Elenchus sought to give due consideration to all of these secondary criteria, where appropriate in reflecting the primary consideration of cost causality.

NEW BRUNSWICK
ENERGY AND UTILITIES BOARD

IN THE MATTER OF a review of New Brunswick Power Corporation's Class Cost Allocation Study (CCAS) methodology (Matter 271)

ORDER

WHEREAS The New Brunswick Energy and Utilities Board (Board) has received an Application from the New Brunswick Power Corporation (NB Power) on October 17, 2014 for approval of its Class Cost Allocation Study (CCAS) Methodology;

AND WHEREAS Registered Parties have filed evidence in the within matter in which alterations have been proposed to the CCAS Methodology submitted by NB Power;

AND WHEREAS at the request of Utilities-Municipal, the Board conducted a Procedural Conference on March 10, 2015 to consider the procedure and schedule for the within Matter;

AND WHEREAS arising from the Procedural Conference NB Power and numerous Interveners have submitted that the alterations proposed require additional study, and NB Power and such Interveners have reached agreement on the procedure and schedule under which additional studies will be conducted;

AND WHEREAS the Board has concluded that such additional study is in the public interest;

NOW THEREFORE IT IS ORDERED THAT:

1. The within Matter is adjourned, subject to the conditions set out in this Order.

2. The Board will consider the within Matter prior to the fixing of rates under Section 103(6) of the *Electricity Act*, S.N.B. 2013, c. 7., in relation to the application of NB Power for approval of its revenue requirement for the 2016/17 fiscal year required under Section 103(1) of the *Act*.

3. NB Power is ordered to conduct a study or studies considering generation cost classification and allocation techniques and methods, which study or studies shall include a recommendation as to whether and how any such techniques and methods should be incorporated into the results of its CCAS Methodology. NB Power shall file such study or studies with the Board no later than May 18, 2015.

4. NB Power is ordered to conduct a study or studies considering the seasonal allocation of costs to rate classes, which study or studies shall include a recommendation as to whether and how any such seasonality should be incorporated into the results of its CCAS Methodology. NB Power shall file such study or studies with the Board no later than October 30, 2015.

5. NB Power is ordered to conduct a study or studies considering the use of multiple coincident peaks, which study or studies shall include a recommendation as to whether and how any such use should be incorporated into the results of its CCAS Methodology. NB Power shall file such study or studies with the Board no later than October 30, 2015.

6. NB Power is ordered to conduct a study or studies considering the update of energy and demand loss factors associated with distribution asset components, which study or studies shall include a recommendation as to whether and how any such update should be incorporated into the results of its CCAS Methodology. NB Power shall file such study or studies with the Board no later than October 30, 2015.

7. NB Power is ordered to conduct a study or studies considering the capital costs versus fuel cost in generation cost classification (break-even analysis), which study or studies shall include a recommendation as to whether and how any such considerations should be incorporated into the results of its CCAS Methodology. NB Power shall file such studies with the Board no later than October 30, 2015.

8. NB Power is ordered to file, by no later than May 15, 2015, a description of the scope of work to be undertaken in relation to each of the studies Ordered in paragraphs 4, 5, 6 and 7 of this Order. Registered Parties may provide comments to NB Power regarding the scope of any study, which comments shall be provided within 14 days of the filing of the description of the scope of work.

9. NB Power is ordered to file, by no later than October 30, 2015, a CCAS Methodology and related evidence giving consideration to the results of the studies Ordered in paragraphs 3, 4, 5, 6 and 7 of this Order, after which time the Board shall hold a Procedural Conference to provide for the continuance of this matter, further IR's with respect to the CCAS Methodology so filed and the holding of a hearing. Further, notwithstanding the dates set out herein by which the Ordered studies are to be filed, all such studies shall be filed no later than the date on which the CCAS Methodology is filed.

10. NB Power is ordered to conduct a study or studies considering methodologies that may improve its estimates of load factors and coincident factors for coincident and non-coincident peaks, which study or studies shall include a recommendation as to whether and how such considerations should be incorporated into the results of its CCAS Methodology. Such study or studies shall be filed with the Board no later than the date of NB Power's filing of its application for approval of its revenue requirement for the 2017/18 fiscal year.

11. NB Power is ordered to conduct a study or studies of sub-functionalization of distribution assets (primary distribution voltage systems versus secondary distribution voltage systems), which study or studies shall include a recommendation as to whether and how such sub-functionalization considerations should be incorporated into the results of its CCAS Methodology. Such study or studies shall be filed with the Board no later than the date of NB Power's filing of its application for approval of its revenue requirement for the 2017/18 fiscal year.

12. NB Power is ordered to file updates on its progress in implementing its advanced metering strategy, such updates to be provided in writing at the end of each fiscal quarter, commencing on September 30, 2015.

DATED at the City of Saint John, New Brunswick, this 9th day of April, 2015.

BY THE BOARD
Kathleen Mitchell
Kathleen Mitchell
Chief Clerk

New Brunswick Energy and Utilities Board
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Memorandum

elenchus

To: **Stephen Russell, NB Power**
From: **John Todd**
Date: **May 12, 2015**
Re: **Scope of Work for CCAS per NBEUB Order, 9 April 2015 (Matter 271)**

This memo sets out a proposed work plan for addressing the Order of the New Brunswick Energy and Utilities Board (Board) dated 9 April 2015 in the matter of a review of New Brunswick Power Corporation's Class Cost Allocation Study (CCAS) methodology (Matter 271) ("Order"). The Order adjourned the Matter, subject to the requirement that NB Power complete seven additional studies and file:

- by 15 May 2015, a description of the scope of work in relation to four of the studies (labelled Studies #2, #3, #4, and #5 below);
- by 18 May 2015, Study #1 considering generation cost classification and allocation techniques and methods which has already been initiated by a consultant to NB Power and will be completed soon;
- by 30 September 2015, updates on its progress in implementing its advanced metering strategy, with further updates at the end of each fiscal quarter;
- by 30 October 2015, Studies #2, #3, #4, and #5, the filing of which will trigger the resumption of the proceeding (Procedural Conference, IR's, etc.); and
- prior to, or as part of, its application for approval of its 2017/18 revenue requirement, Studies #6 and #7.

The seven studies specified in the Order are:

Study #1: Generation cost classification and allocation techniques and methods

Study #2: Consideration of seasonal allocation of costs to rate classes

Study #3: Consideration of the use of multiple coincident peaks

Study #4: Consideration of updated energy and demand loss factors associated with the distribution assets components

Study #5: Consideration of the Capital Cost Versus Fuel Cost in generation cost classification (break-even analysis)

Study #6: Consideration of methodologies that may improve the estimates of load factors and coincident factors for CP and NCP allocators

Study #7: An Analysis of sub-functionalization of distribution assets (primary distribution voltage versus secondary distribution voltage systems)

34 King Street East, Suite 600, Toronto, Ontario, M5C 2X8
Email: JTodd@elenchus.ca; direct line: 416-348-9910

OVERVIEW COMMENTS

As a consequence of this Order, NB Power will be required to file an updated CCAS that will include any appropriate updates resulting from Studies #1 through #5 as a basis for setting rates for the 2016/17 fiscal year. In addition, NB Power will be required to file a further updated CCAS that will include any appropriate revisions resulting from Studies #1 through #7 as a basis for setting rates for the 2017/18 fiscal year.

Consequently, it will be important that the analysis undertaken for each of these studies and the resulting recommendations are consistent in that they will work together to produce a result that allocates costs to customer classes in a manner that reflects cost causality as effectively as possible. In doing so, the resulting rates for all customer classes must be just and reasonable taking into account the CCAS and rate design considerations including rate stability.

The issues addressed in several of the required studies are interrelated and as a result undertaking the project jointly will not only be more efficient but it is also the best way to ensure that the recommendations with respect to all issues are consistent.

It is therefore recommended that NB Power undertake a comprehensive review of its CCAS methodology with the seven studies identified in the Board Order included as part of this comprehensive review.

PROPOSED PROJECT PLAN

The CCAS Review will include a review of each of the three basic steps in a class cost allocation study as identified in the prefiled evidence of NB Power at page 3:

Step 1: Functionalization

Step 2: Classification

Step 3: Allocation

Two parallel projects will be undertaken to address the methodology used to develop information that serves as inputs to the CCAS:

- update of the load profiles of the customer classes which serve as the basis for determining load factors, coincident peak factors and non-coincident peak factors that underpin the allocators used to allocate functionally classified costs to the customer classes (**Study #6**, identified above); and
- update of the energy and demand loss factors that are used in deriving the energy and demand allocators used to allocate functionally classified costs to the customer classes (**Study #4**)

Review of Functionalization Methodology

The methodology used by NB Power to functionalize its costs into the four basic functions (production, transmission, distribution and customer service) will be reviewed in detail. The current methodology is summarized in the NB Power's prefiled evidence Appendix 1, pages 3 – 5, with further details being provided in the tables contained in Appendix 2.

This review will include specific consideration of:

- the implications, if any, of the recommendations that are included in **Study #1** which is to be completed by 18 May 2015;
- the basis for the division of distribution assets into Primary and Secondary sub-functions as shown in Appendix 2, Addendum IV (**Study #7**); and
- the appropriateness of creating sub-functional classifications based on seasonal considerations (**Study #2**).

Review of Classification Methodology

The methodology used by NB Power to classify its functionalized costs into demand/ capacity, energy and customer components will be reviewed in detail. The current methodology is summarized in NB Power's prefiled evidence Appendix 1, pages 5 – 7, with further details being provided in the tables contained in Appendix 2.

This review will include specific consideration of:

- the implications, if any, of the recommendations that are included in **Study #1** which is to be completed by 18 May 2015; and
- the merit in classifying certain generation costs on the basis of an analysis of the break-even level of generation for capital costs versus fuel costs (**Study #5**).

Review of Allocation Methodology

The methodology used by NB Power to allocate its functionally classified costs to the customer classes will be reviewed in detail. The current methodology is summarized in the prefiled evidence Appendix 1, pages 3 – 5, with further details being provided in the tables contained in Appendix 2.

This review will include specific consideration of:

- the implications, if any, of the recommendations that are included in **Study #1** which is to be completed by 18 May 2015;
- whether it is appropriate to implement allocators for certain categories of functionally classified costs that reflect differing operational, demand and/or

energy characteristics by season, and if so, which costs should be allocated in this manner and what allocators should be used (**Study #2**);

- whether it is appropriate to implement allocators based on multiple coincident (or non-coincident) peaks, such as 4CP or 12CP or an averaging of 3 or more hourly peaks that occur within a peak month, or other period (**Study #3**); and
- implementing modified allocators that incorporate updated loss factors (**Study #4**) and updated load and coincident peak factors (**Study #6**).

Methodology for the Reviews of Each Stage

The recommended approach involves undertaking the review in six phases. It is recommended that a stakeholder engagement process be implemented to provide an opportunity for stakeholders to provide input on a regular basis.

Phase 1: Conceptual analysis of all issues. This phase will include a review of the theory underlying each stage (functionalization, classification and allocation). For all relevant issues as identified above or as identified as an additional issue that should be examined, the analysis will include the identification of options for addressing the issue, the rationale for each option, and an assessment of the pros and cons of each option based on theoretical and pragmatic considerations. A stakeholder session will be convened to provide an opportunity to stakeholders to comment on the analysis and to identify additional options that they believe should be addressed.

Phase 2: Detailed analysis for implementing appropriate options. This phase will entail detailed analysis of options that are appropriate based on the conceptual analysis in Phase 1. This analysis will include consideration in light of the operating characteristics of the NB Power system. It will also identify the data that will be required to implement each option.

Phase 3: Assessment of data availability and cost in order to make final recommendations. This phase will assess the reasonableness of each option from a value versus effort perspective and make recommendations.

Phase 4: Update the CCAS as appropriate for the 2016/2017 GRA. An updated version of the CCAS will be prepared that incorporates the results of Studies #1 through #5, as deemed appropriate by NB Power. Evidence will be prepared that fully documents the updated CCAS and explains the rationale for all changes from NB Power’s current CCAS. The evidence will include details of the incremental impacts on 2016/17 allocated costs resulting from each of the changes incorporated into the CCAS. The evidence will also include the incremental impacts of any changes that stakeholders would support, based on input provided during the stakeholder engagement process, but are not incorporated in the NB Power CCAS.

Phase 5: Update of class load profiles. An improved methodology will be implemented for estimating the load profiles of all customer classes as a basis for the load factors and the coincident and non-coincident peak allocators to be used in the 2017/18 CCAS.

Phase 6: Update the CCAS as appropriate for the 2017/2018 GRA. An updated version of the CCAS will be prepared that incorporates the results of Studies #1 through #7, as deemed appropriate by NB Power. Evidence will be prepared that fully documents the updated CCAS and explain the rationale for all changes from NB Power's 2016/17 CCAS. The evidence will include details of the incremental impacts on 2017/18 allocated costs resulting from each of the changes incorporated into the CCAS associated with Studies #6 and #7. The evidence will also include the incremental impacts of any changes related to Studies #6 and #7 that stakeholders would support, based on input provided during the stakeholder engagement process, that are not incorporated in the NB Power 2017/2018 CCAS.

Proposed Timing for Deliverables

Circulate to stakeholders this description of the Scope of Work for the entire work plan: April 23, 2015.

Complete Phase #1 and conduct a stakeholder session by May 11, 2015.

File with the Board the finalized description of the Scope of Work for the entire work plan including the options to be considered for Studies #2 through #5 by May 15, 2015.

Study #1 filed with the Board by May 18.

Second stakeholder meeting in mid-July.

File evidence that incorporates Studies #1 through #5 by October 30, 2015. This filing will include the final reports for Studies #2 through #5.

Complete additional Load Research (Study #6) and the review of the sub-functionalization of distribution assets (Study #7) prior to NB Power filing its 2017/18 GRA.

SCOPE OF WORK (FOR THE PROJECTS LISTED IN THE BOARD ORDER)

As noted above, paragraph 8 of the Order directed NB Power "to file, by no later than May 15, 2015, a description of the scope of work to be undertaken in relation to each of the studies Ordered in paragraphs 4, 5, 6 and 7." These studies correspond to the studies labelled Studies #2, #3, #4, and #5 above. Based on the overall project plan set out above, the initial description of the scope of work for these studies is outlined below. These studies are incorporated into Phases 1 through 4, as described above.

Study #2: Consideration of seasonal allocation of costs to rate classes

Task #1: Review existing class load profiles to determine differences across classes.

Task #2: Review seasonality of generation station operations to identify differences in average and marginal operating costs and purchase power costs across seasons.

Task #3: Review seasonality of export revenues to identify differences in average export revenue across seasons.

Task #4: Develop options for recognizing seasonality for rate-setting purposes through the CCAS methodology.[1]

Task #5: Assess the conceptual rationales and the advantages/disadvantages of each Task #4 option.

Task #6: Examine the impact of on the costs allocated to each class of each option by modifying the current 2015-16 CCAS (Exhibit NBP 6.02).

Study #3: Consideration of the use of multiple coincident peaks

Task #1: Review and refine NB Power's methodology for estimating the actual hourly loads for all rate classes for all 8760 hours in an historic year (actual load profiles) and for the hypothetical load profiles under normal weather conditions.

Task #2: Assess the confidence interval for the Task #1 load profiles.

Task #3: Derive 1-CP, 2-CP, 3-CP, 4-CP 6-CP and 12-CP allocators (single monthly peaks) and variants with multiple peak hours within a month, based on the hypothetical load profiles produced in Task #1.

[1] Although rate design issues are outside the scope of this project, it should be noted that consideration of the allocation of seasonal costs will necessarily recognize that seasonality of costs implies consideration of alternative rate designs based on the allocated seasonal costs.

Task #4: Examine the impact of on the costs allocated to each class of using the derived allocators by modifying the current 2015-16 CCAS (Exhibit NBP 6.02).

Study #4: Consideration of updated energy and demand loss factors associated with the distribution assets components

Task #1: Review and refine NB Power's methodology for estimating energy (i.e., average) and demand (i.e., peak or multiple peak) loss factors for each distribution sub-function (primary and secondary). Both metering and engineering analysis will be considered in seeking the best available loss factor estimates.

Task #2: Assess the confidence interval for the Task #1 loss factor estimates.

Task #3: Derive refined energy and demand allocators that reflect the refined loss factors derived in Task #1.

Task #4: Examine the impact of on the costs allocated to each class of using the revised allocators by modifying the current 2015-16 CCAS (Exhibit NBP 6.02).

Study #5: Consideration of the Capital Cost Versus Fuel Cost in generation cost classification (break-even analysis)

Task #1: Determine the break-even point (operating hours) for each of the distinct generation technologies in the NB Power fleet and for the notional peaker plant used as a basis for the demand-energy split of production fixed costs.

Task #2: Develop options for modifying the Peaker Credit Method by allocating the non-demand portion of the functionally classified costs to customer classes on the basis of the energy usage break-even number of hours of highest demand.

Task #3: Assess the conceptual rationales and the advantages/disadvantages of each Task #2 option.

Task #4 Derive refined energy and demand allocators that reflect each identified for implementing the proposed break-even concept for modifying the Peaker Credit Method.

Task #5: Examine the impact of on the costs allocated to each class of using the revised allocators by modifying the current 2015-16 CCAS (Exhibit NBP 6.02).

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HQEM-APPRO INTERROGATORY 18

Issue 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-HQEM-APPrO-IR18

INTERROGATORY

Reference: Elenchus' October 22, 2015 report titled "New Brunswick Power Customer Cost Allocation Study Review" prepared on behalf of New Brunswick Power, page 8.

(i) In accordance with Elenchus' comments on page 8 of its New Brunswick report – why wasn't this range of 0.95 – 1.10 recommended as an option in the Ontario cost allocation study? Can Elenchus explain how distribution customer classes (as analyzed in each of New Brunswick and Ontario) differ enough so as to justify a wider zone of reasonableness for customer classes in Ontario?

RESPONSE

(ii) Elenchus did not recommend a revenue-to-cost ratio range either in the NB Power study or the IESO study. In the view of Elenchus, the range that is appropriate is not a matter that is within the scope of a cost of service study. That is a determination that is an element of rate design. In both cases, Elenchus adopted the most readily available range that had regulatory approval in the relevant jurisdiction as a basis for illustrating the potential rate impacts of the cost of services study. Differences in revenue-to-cost ratios are a matter of historical precedent and the judgment of individual regulators on a case-by-case basis.

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HQEM-APPRO INTERROGATORY 19

Issue 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-HQEM-APPrO-IR19

INTERROGATORY

Reference: Elenchus evidence filed as Exhibit B-1-1, Attachment 3 of the IESO's 2016 revenue requirement submission section 1, page 6, lines 11-13; page 9, line 23; section 2.3, page 9, lines 25-28; and section 2.4, page 10, lines 2-4

(i) The IESO fee has been charged since it was created (under a different name) in 2002. The OPA was established in 2004 and with it came the OPA fee for customers in Ontario only. Please confirm that since 2004, two separate fees have been charged?

(ii) If the answer to 1.2(a) is yes, please confirm that existing settlement systems can currently accommodate charging separate fees?

(iii) If existing systems accommodate charging the fees separately, why would continuing to charge separate fees add increased administrative burden?

(iv) Please quantify the costs of changing the current system to charge a single fee.

(v) Please confirm which of the principles referred to or alluded to in the study (section 2.3 and 2.4) as being key considerations (administrative simplicity, equity and cost causality) were most important to the IESO. If they were all considered equally "key" principles how was the value of administrative cost – as it relates to determining the administrative simplicity of having a uniform rate versus two separate rates -- quantified by Elenchus?

RESPONSE

(i) The IESO fee (charge type 9990) and the OPA fee (charge type 754) have been charged separately since 2002 and 2005 respectively. Post the merger date of January 1, 2015, they continue to be charged as two fees as per section 25.(9) of the Electricity Act, 1998.

(ii) While the reference to "1.2(a)" is not clear, as described in i) above, the current settlement system can accommodate the separate fees.

(iii) The increased administrative burden is not associated with the settlement of the fee. The operation and maintenance associated with two fees is inherently greater than that associated with one fee. In addition, charging separate fees for exporters and domestic customers would require the IESO to track and set costs for customer classes for which there is no basis to easily or directly attribute those costs. As described in Exhibit B-1-1, Attachment 3 on page 10:

> *In conducting this work, Elenchus has observed that the IESO's costs that are recovered through its Usage Fee consist largely of costs that would be treated as operational overhead or administrative and general (A&G) costs in the cost allocation models that are typically used by regulated electric utilities for their rate setting processes.*

The IESO does not believe that there is value for ratepayers in trying to separate costs to customer classes when there is no basis to effectively allocate these costs.

(iv) There would be virtually no cost for changing the settlement system to charge a single fee. Currently the IESO fee charge type charges domestic customers based on Allocated Quantity of Energy Withdrawn (AQEW) plus generation embedded in LDCs and exporters based Scheduled Quantity of Energy Withdrawn (SQEW). Under the proposed IESO usage fee, this methodology would continue. Therefore, changing the settlement system to charge a single fee would only require a rate change in the settlement system. The current OPA fee charge type would be disabled in the settlement system.

(v) Please see the response to HQEM-APPrO Interrogatory 17(iii), at Exhibit I, Tab 2.1, Schedule 6.17, which confirms that cost causality is the primary principle relied on by Elenchus. The other principles identified were secondary considerations.

In the context of a cost allocation model, administrative simplicity refers to the effort required to provide the inputs required to generate the data needed to implement the model. Any administrative costs associated with having a uniform versus two separate rates is not relevant to the administrative simplicity associated with the cost allocation model. This administrative cost was not considered or quantified by Elenchus in developing the IESO's cost allocation model.

Costs associated with the implementation of alternative rate designs, if significant, would be a consideration in the rate design step in ratemaking, not cost allocation. The IESO notes that the difference in administrative costs for a uniform versus two separate rates would not be significant, as described above. The current IESO billing system accommodates fees with different domestic and export customers.

HQEM-APPRO INTERROGATORY 20

Issue 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-HQEM-APPrO-IR20

INTERROGATORY

Reference: Elenchus evidence filed as Exhibit B-1-1, Attachment 3 of the IESO's 2016 revenue requirement submission section 4.1, page 13, line 25 and page 14, line 6

(i) Please clarify what the OPA portion of the merged revenue requirement is in dollars, as referred to here, and estimate the cost of the portion that relates to Ontario electricity system planning functions.

RESPONSE

The IESO is not able to split out the OPA portion of the merged revenue requirement as since the merger of the IESO and OPA on January 1, 2015, the organization has operated as a single entity, with one set of books. As stated in Exhibit A-1-1, page 3, "As the merger of the IESO and OPA took effect on January 1, 2015...The IESO only recorded IESO expenses in 2015, no expenses in 2015 were recorded as OPA expenses."

The budget for the transmission, generation and conservation planning groups at the IESO totals $4.73 million, which would be largely representative of the costs of the electricity planning functions at the IESO.

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HQEM-APPRO INTERROGATORY 21

Issue 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-HQEM-APPrO-IR21

INTERROGATORY

Reference: Elenchus evidence filed as Exhibit B-1-1, Attachment 3 of the IESO's 2016 revenue requirement submission section 4.3, page 14, lines 17-19

(i) Please detail the reasons that the OEB-approved model and range for distribution customer classes was considered by Elenchus to be an appropriate benchmark when determining equitable rate treatment for domestic and export customer classes.

RESPONSE

(i) Elenchus has not asserted that the OEB-approved model and range for distribution customer classes is an appropriate benchmark for determining equitable rate treatment for the domestic and export customer classes. The Elenchus evidence states only that "if the OEB were to adopt an R/C ratio range of 80% to 120% for the IESO's usage fee, it would follow that …" (page 15, lines 16-17). In the absence of an OEB approved revenue-to-cost ratio range for the IESO, Elenchus used the most common OEB approved range for regulated electricity entities for purposes of illustrating the methodology that Elenchus considers appropriate for making a determination about customer classification (one or two classes) based on allocated costs. Zones of reasonableness are generally a matter of the judgment of regulators as there is no generally accepted quantitative methodology for determining an appropriate zone of reasonableness to be used for any particular entity. The selection of an appropriate R/C ratio range is a matter that is appropriately addressed as part of rate design, not cost allocation.

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HQEM-APPRO INTERROGATORY 22

Issue 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-HQEM-APPrO-IR22

INTERROGATORY

Reference: Elenchus evidence filed as Exhibit B-1-1, Attachment 3 of the IESO's 2016 revenue requirement submission section 5, page 17, lines 9-12

(i) Please clarify the customer classes served by distributors and the identifiable causes and benefits that those customer classes receive from their distributor. What "easily identifiable" benefits do each of these customer classes in a distribution system receive?

(ii) What additional easily identifiable benefits do export customers receive subsequent to the IESO-OPA merger that they did not receive prior to the merger?

(iii) Please elaborate on which distribution customer class out of the ones described above most closely resembles an export customer in a transmission system.

RESPONSE

(i) The primary differences between classes, is the types of costs they cause. For example, some classes which do not make use of secondary distribution assets are not allocated secondary distribution costs.

(ii) Please see the response to HQEM-APPRO Interrogatory 13, at Exhibit I, Tab 2.1, Schedule 6.13.

(iii) The Elenchus evidence refers to the classes as being analogous in that they are identifiable as causing significantly different costs. Being analogous was not intended to imply that they resemble each other in terms of specific customer characteristics. As is the case with other customer class definitions, it is customers within a class that have similar characteristics, not customers in different classes served by different entities. The classes are analogous in that customers are more homogenous within a class than they are between classes.

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HQEM-APPRO INTERROGATORY 23

Issue 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-HQEM-APPrO-IR23

INTERROGATORY

Reference: Elenchus evidence filed as Exhibit B-1-1, Attachment 3 of the IESO's 2016 revenue requirement submission section 1, page 6, lines 15-20

(i) What assumptions would need to change in the model for the revenue-to-cost ratio to exceed 120% for the export customer class? Did Elenchus perform any sensitivities related to its analysis? If so, please discuss.

(ii) Please clarify what is meant by "approved range for the rates of **most** (emphasis added) distribution customer classes" – by "most" does Elenchus mean to say that there are distribution customer classes that do not use this range? If so, why not?

(iii) Can Elenchus describe what revenue-to-cost ratio range, or in other words, what zones of reasonableness ("ZORs") are used in other states and provinces, and how the range in Ontario compares?

RESPONSE

(i) The revenue-to-cost ratio for the export class could exceed 120% for any number of reasons, including differences in costs, volumes, and allocator chosen to reflect cost causation. Elenchus has relied on cost information as well as domestic and export volumes provided to it by the IESO. To the best of Elenchus' knowledge, this information is accurate; hence, it was not the subject of sensitivity analysis. However, the shift in loads used for the 2015 model which was filed in January and the 2016 model provides relevant sensitivity analysis for the shifts that can happen from one year to the next. The change in the share of KWhs was the key driver that changed the revenue-to-cost ratios.

Elenchus has performed sensitivity analysis around some of the allocators that relied on judgment. There was one instance in which the allocator selected by Elenchus resulted in a higher allocation of costs to the export class than an alternative that was considered credible. As a sensitivity, costs related to the Strategic Engagement & Innovation group of the Conservation and Corporate Relations Business unit were allocated to Domestic use, rather than on the basis of TWh as proposed. This sensitivity increased the revenue-to-cost ratio for the export class to 122.18%. Elenchus believes that the TWh allocator is more appropriate for this group as it performs functions crossing the company including government affairs.

There were two instances in which the allocator selected by Elenchus resulted in a lower allocation of costs to the export costs than an alternative that was considered credible. As a sensitivity, costs related to the Reliability Assessments Group of the Market and System Operations Business unit were modelled as being 50% Export and 50% Domestic rather than on the basis of TWh as proposed. In addition, the Transmission Integration group of the Planning, Law, and Aboriginal Relations Business unit was modelled on the basis of TWh rather than on the basis of Domestic. These two changes together reduced the revenue-to-cost ratio of the export customer class to 104.27%.

Elenchus understands that there are units that are engaged in activities that are primarily in support of NERC and NPCC activities. For example, the primary function of the Interconnected Network Studies group within Reliability Assessments is to support NERC and NPCC activities. While this role could justify an increased allocation of costs to export, Elenchus recognized that these activities also benefit domestic customers indirectly; hence, in the interest of conservatism, the TWh allocator was used in the model. Also, the entire Planning, Law, and Aboriginal Relation business unit is understood to fulfill a domestic need, therefore the domestic allocation is proposed.

These sensitivities provided Elenchus with comfort it sought that overall the allocators selected were conservative and did not bias the result toward minimizing the differential in the revenue-to-cost ratios of the export and domestic classes.

(ii) As Table 2 on page 16 of the Elenchus evidence shows, not all classes have OEB approved ranges of 80 to 120%. The ranges were established by the Board as a matter of policy.

(iii) Elenchus has not conducted a survey of the revenue-to-cost ratio ranges that are used in other states and provinces. In Elenchus' view, no relevant information could be obtained by doing so since, as far as Elenchus has been able to determine, no other North American system operator recovers its fees through a separate fee as opposed to embedding the recovery of its costs in the relevant transmission tariffs. When ranges are explicitly recognized, the regulatory decisions, if available, would be important to appreciating the circumstances and rationale for each regulatory decision. These decisions are made within the context of many rate design considerations. The appropriate revenue-to-cost ratio is a matter that is a consideration in designing rates; it is not a consideration that is embedded in cost allocation models. An approved revenue-to-cost ratio range is also typically a consideration in defining customer classes (customer classification).

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HQEM-APPRO INTERROGATORY 24

Issue 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-HQEM-APPrO-IR24

INTERROGATORY

Reference: Elenchus evidence filed as Exhibit B-1-1, Attachment 3 of the IESO's 2016 revenue requirement submission section 1, page 6, lines 20-23

(i) Can Elenchus confirm that by this statement, it means to say that there is a 20% uncertainty in cost allocation? What are the particular sources of this uncertainty? Once a particular cost allocation has been determined, why is there any uncertainty at all thereafter?

(ii) Can Elenchus clarify what other ratemaking principles were accommodated in its study besides the revenue-to-cost principle?

(iii) Please advise whether there are data quality issues that prevent a revenue to cost ratio of greater than 1:1?

(iv) Please advise whether the IESO has current plans to improve its accounting and load data to see if there modifications that can be made to permit a revenue to cost ratio of closer to 1:1.

(v) Please advise whether, with more experience in cost allocation concepts, the IESO expects to be better able to achieve a revenue to cost ratio of 1:1.

RESPONSE

(i) Elenchus is not aware of decisions of regulators with respect to what they determine to be appropriate revenue-to-cost ratio ranges that are based on quantitative analysis of the uncertainty in cost allocation models. Rather, the decisions appear to be based on the regulator's judgment as to the range that is appropriate to use in setting just and reasonable rates. In the view of Elenchus, what can be characterized as uncertainty – or imprecision as distinct from the statistical concept of uncertainty – relates to the absence of precise causal linkages between customer classes and the costs they cause. The only case where the allocation of costs can be viewed as having a direct and unequivocal causal relationship is where costs are directly allocated, although even these cases are not always free of disagreement among stakeholders and experts.

(ii) Elenchus relied on cost causality as the primary consideration in developing the IESO cost allocation model. Most other ratemaking principles, including those listed in the Elenchus evidence, are principles that are relevant to rate design as opposed to cost allocation. Elenchus is not aware of any cost allocation expert that considers there to be a revenue-to-cost principle to exist; revenue-to-cost ratios are a consideration in rate design. A consideration is not a principle. Also see the response to HQEM-APPrO Interrogatory 17, at Exhibit I, Tab 2.1, Schedule 6.17.

(iii) In the view of Elenchus, the most relevant consideration that may result in rate designs that have revenue-to-cost ratios that vary from 100%, as in the case of the IESO, is the concern that the causal link between export and domestic customers and most of the IESO's costs is exceptionally weak. As the evidence states, most costs are akin to A&G costs. These types of costs rely on allocators that rarely have a clear causal basis.

(iv) In Elenchus' view, the imprecision of the cost allocation results is not the result of accounting or load data, it is the nature of the costs involved. See the response to part (iii) above.

(v) In Elenchus' view, in the case of the IESO, experience will not change the nature of the costs and the lack of clear cost causality.

HQEM-APPRO INTERROGATORY 25

Issue 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-HQEM-APPrO-IR25

INTERROGATORY

Reference: In its original report dated January, 2016, Elenchus estimated the cost allocation ratio for exporters would be 114.3%. Its new evidence (May, 2016), increases the subsidy from exporters to domestic customers from 14.3% above unity to 19.32 % above unity, an increase in the subsidy by close to 26% in just 3 months. This dramatic change resulted despite the fact that both the increase in total costs and the increase in total volumes was, in each case, less than .01%.

(i) Please explain the factors that led to such a large proposed increase in subsidy from such a relatively small change in underlying costs and volumes.

(ii) Please advise what the revenue to cost ratios have been for exporters since the IESO first began charging exporters a usage fee.

(iii) Please provide copies of cost allocation studies used to support charging the IESO's existing fee to exporters.

(iv) The OEB's November 28, 2007 Report on Application of Cost Allocation for Electricity Distributors (EB-2007-0667), stated at p. 6: "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)

Please advise how Elenchus considered the need for stability in developing its model.

(v) In the same report, the OEB stated that "A principle of rate making is the avoidance of rate shock. Proposed rate changes should consider the ability of consumers to react to their new costs" (p.6). Exporters currently pay a usage fee of $.803/MWh. If the IESO's proposal is accepted, Exporters will be paying a usage fee of $1.13/MWh: an increase of 41%. Please provide evidence of how Elenchus considered rate shock in developing this proposal

RESPONSE

(i) The change in allocated costs is driven primarily by the change in the proportion of forecast load for the domestic and export classes. Even if both total costs and total load were constant, a shift in the proportional share of load associated with each class will change the apportionment of costs to the classes. The same effect occurs when a significant load within a distributor's customer class is added or lost, thereby changing the proportionate allocation of common costs.

(ii) There is no cost allocation model for the IESO based on its pre-merger operations; hence, the requested ratios are not available.

(iii) The IESO's existing fees were not based on a cost allocation model.

(iv) The rate making principles identified in the question are important rate design considerations; however, they are not a consideration in developing a cost allocation methodology. In Elenchus' view, having developed what it considers to be the most appropriate cost allocation model for allocating costs to the domestic and export class, the observed instability raises questions about the approach to rate design that is appropriate. Elenchus notes that similar issues do not arise for other North American system operators since their fees are embedded in the transmission rates that they administer.

(v) Rate making refers to both cost allocation and the follow-up step of rate design. Hence, rate making principles include principles that relate to both steps in rate making. The avoidance of rate shock is a rate making principle that is addressed through rate design, not cost allocation. The Elenchus mandate in this proceeding was to develop a cost allocation model as per the direction of the OEB in decision EB-2010-0279. Rate design considerations are not addressed.

HQEM-APPRO INTERROGATORY 26

Issue 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-HQEM-APPrO-IR26

INTERROGATORY

Reference: Elenchus evidence filed as Exhibit B-1-1, Attachment 3 of the IESO's 2016 revenue requirement submission section page 13, lines 22-25

(i) Can Elenchus confirm that since the allocation study performed determined export customers revenue-to-cost ratio (119.32%) was at the edge of the allowable zone of reasonableness of 120%, even a minor change to the study's assumptions could push the export class outside of the zone of reasonableness, thereby making the IESO proposal inconsistent with cost causality?

RESPONSE

(i) If the OEB adopts an approved revenue-to-cost ratio range of 80% to 120%, the IESO proposal would not be inconsistent with the results of the current cost allocation model. Elenchus can confirm that a small further decrease in the relative costs allocated to the export class could result in the export class having a revenue-to-cost ratio that is above the 120% threshold.

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HQEM-APPRO INTERROGATORY 27

Issue 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-HQEM-APPrO-IR27

INTERROGATORY

Reference: Elenchus evidence filed as Exhibit B-1-1, Attachment 3 of the IESO's 2016 revenue requirement submission section page 15, lines 12-13

(i) Please advise what steps Elenchus has taken to try to move the IESO's revenue to cost ratios to unity.

(ii) What would the rate be if it produced a revenue cost ratio of 1:1?

RESPONSE

(i) Elenchus has taken no steps in developing the IESO's cost allocation model to try to move the IESO's revenue to cost ratios to unity. Doing so would be a violation of Elenchus' view of the purpose of developing a cost allocation model. Shifting revenue to cost ratios toward unity is accomplished through rate design, not changes in the cost allocation methodology. Specifically, revenue to cost ratios can be intentionally changed through differential rate adjustments.

(ii) The rates that would result in 100% revenue-to-cost ratios are shown in Table 1 at page 15 of the Elenchus evidence. See the column labelled 100% RCR under Class-Specific Usage Fees.

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HQEM-APPRO INTERROGATORY 28

Issue 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-HQEM-APPrO-IR28

INTERROGATORY

Reference: Elenchus evidence Exhibit B-1-1, Attachment 3 of the IESO's 2016 revenue requirement submission page 16, Table 2 "Revenue-to-Cost Ratio Ranges" contains a "Large User" service class and "Residential" service class with the corresponding ranges of 85 – 115%.

On page 16, lines 9-11 state, "…if either R/C ratio is outside of the OEB-approved range, then it may justify establishing separate domestic and export classes for the purposes of the IESO usage fee."

(i) Given that Table 2 shows two large classes for which the upper bound of the target range is reached at 115%, and that exporters may well be considered "large users", isn't it true that 115% could be a plausible threshold for the export class range, and thus the proposal would be inequitable since exporters would be outside of the range of reasonableness? If so, would separate rates be justified?

RESPONSE

(i) If the OEB adopts a revenue-to-cost ratio range with an upper limit of 115% (or an upper limit below 115%), then based on the Elenchus cost allocation model for the IESO, the export class would exceed that upper limit. The implications of that result would be a matter to take into account in designing the IESO rates and/or customer classes.

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HQEM-APPRO INTERROGATORY 29

Issues 2.2 and 2.3: Is the Methodology used to derive the proposed IESO Usage Fee of 1.13/MWh appropriate?

2-HQEM-APPrO-IR29

INTERROGATORY

Reference: Cost Allocation and Rate Design for the 2016 Fees of the IESO ("Elenchus Report"), Exhibit B-1-1, Attachment 3, page 11

(i) Please advise why Elenchus believes that "allocating costs in a manner consistent with the IESO's existing MWh based Usage Fee" is the appropriate criteria for evaluating revenue to cost ratios?

(ii) What criteria other than consistency with the IESO's existing MWh based Usage fee did Elenchus consider? If none, why did Elenchus not consider other criteria?

(iii) The evidence states that "Alternative fee designs would require quite different approaches to allocating the IESO's costs." Please identify what "Alternative fee designs" are contemplated in this statement.

(iv) Please provide all analysis undertaken by reference to "alternative fee designs".

(v) Please advise of the criteria used by Elenchus to determine that "alternative fee designs" should not be applied.

(vi) Please advise whether the decision to not consider alternative fee designs was made by the IESO or by Elenchus.

RESPONSE

(i) The quoted statement was not intended to imply that "allocating costs in a manner consistent with the IESO's existing MWh based Usage Fee" is the appropriate criterion for evaluating revenue to cost ratios. The point being made was that the component of the OEB-approved fee structure that is being addressed by the IESO cost allocation study (there are also fixed fees which are beyond the scope of this study) is a variable rate based on energy (MWh). In Elenchus' view, this OEB-approved approach implies that there is historical confirmation that an energy allocator of common IESO costs is reasonable. In particular, it is Elenchus' view that energy is a more reasonable and equitable indicator of cost causality for the IESO's common costs than demand (MW) or customer connections, which are commonly used additional allocators.

(ii) See the response to part (i), above. Consistency was not a criterion that Elenchus considered. The primary criterion was cost causality, subject to consideration of feasibility and practicality.

(iii) The quoted sentence appears in the Elenchus evidence at page 11, lines 10-11. An alternative that would be consistent with the way in which other North American system operators recover their costs would be to embed the system operator's costs in the transmission rates that they administer. This approach would be inconsistent with the current OEB- approved cost recovery method (a separate system operator usage fee).

(iv) No analysis has been undertaken with respect to "alternative fee designs" as the issue was beyond the scope of cost allocation evidence.

(v) See the response to part (iv), above.

(vi) No such decision was made by either the IESO or Elenchus. Alternatives to the current OEB-approved fee design was not identified as an issue to be addressed by the OEB or any stakeholder.

HQEM-APPRO INTERROGATORY 30

Issues 2.2 and 2.3: Is the Methodology used to derive the proposed IESO Usage Fee of 1.13/MWh appropriate?

2-HQEM-APPrO-IR30

INTERROGATORY

Reference: Cost Allocation and Rate Design for the 2016 Fees of the IESO (“Elenchus Report”), Exhibit B-1-1, Attachment 3, s. 5.1.1. The exhibit provides the allocators used for each department within each business unit of the IESO.

(i) Please provide further rationale and provide metrics developed or applied by Elenchus, supporting the choice of the proposed allocator for each of the following departments, with emphasis on the allocation to “exports” as opposed to a domestic customer allocation only:

(a) Market Forecast and Integration (allocator proposed: Pro-Rated to Export TWh);

(b) Interest (allocator proposed: Pro-Rated to Export TWh);

(c) Reliability Assessments (allocator proposed: Pro-Rated to Export TWh); and

(d) Operational Effectiveness (allocator proposed: Pro-Rated to Export TWh

RESPONSE

(i) Elenchus relied on judgment based on the information provided by the IESO. The information provided is summarized in section 5 of the Elenchus report. Where the most reasonable allocator was not clear based on the initial information provided, Elenchus augmented its understanding of the operations of departments with interviews of managers. The essence of the judgments made was whether the activities related to each cost category were related primarily to the overall operation of the IESO-administered market or primarily to either domestic or export usage of the system. The IESO does not maintain metrics that relate to the use of the system by export and domestic customers other than the TWh measure.

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HQEM-APPRO INTERROGATORY 31

Issues 2.2 and 2.3: Is the Methodology used to derive the proposed IESO Usage Fee of 1.13/MWh appropriate?

2-HQEM-APPrO-IR31

INTERROGATORY

Reference: Cost Allocation and Rate Design for the 2016 Fees of the IESO (“Elenchus Report”), Exhibit B-1-1, Attachment 3, s. 5.1.1.

(i) Please specify how Elenchus allocated “Total Other OM&A” among export and domestic load.

RESPONSE

(i) As explained in the Elenchus report at page 35, lines 1-5: “The cost of groups that functionally support the rest of the organization are allocated to the classes in the same proportion as the costs of the direct market support functions are allocated (i.e., Other OM&A). This allocation is used for the CEO Office, Information and Technology Services and three of the five groups within Corporate Services (Financial Planning & Analysis, Treasury & Pension and Human Resources).” In other words, the allocation of these overhead costs is in the same proportion as all other costs that are allocated to classes.

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HQEM-APPRO INTERROGATORY 32

Issues 2.2 and 2.3: Is the Methodology used to derive the proposed IESO Usage Fee of 1.13/MWh appropriate?

2-HQEM-APPrO-IR32

INTERROGATORY

Reference: Cost Allocation and Rate Design for the 2016 Fees of the IESO ("Elenchus Report"), Exhibit B-1-1, Attachment 3, p. 34. The evidence states that "the size of the business units is influenced by the scale of the overall electricity market in Ontario."

(i) Please advise of annual percentage changes to the size and expense of the business units referred to in the evidence and the annual percentage changes to electricity production and consumption in Ontario over the last five years.

The evidence states that "it is reasonable to view the benefit that is derived by participants in the market as being proportionate to the volume of energy transmitted."

(ii) Please confirm that the IESO's costs do not change by reference to the volume of electricity transmitted.

RESPONSE

(i) The quotation referred to in the question should be understood in the context of the full paragraph which states:

> *Shared expenses relate to functions that are necessary to serve both domestic and export customers, including the operation of the market and overall operation of the IESO. <u>These expenses are essentially fixed and are required regardless of throughput.</u> However, the size of the business units is influenced by the scale of the overall electricity market in Ontario. Further, it is reasonable to view the benefit that is derived by participants in the market as being proportionate to the volume of energy transmitted. For that reason, where a service is used by all customers the cost is normally considered to be energy related and costs are allocated on the basis of TWhs. (emphasis added)*

In particular, the underlined sentence emphasizes that the expenses do not vary directly with scale. To clarify, the intent was to suggest that in the short run, and for anything other than significant changes in scale, costs would be "essentially fixed". Nevertheless, if scale were to increase or decrease by 50%, for example, it would be reasonable to expect that costs would also move in the same direction, although probably not to the same degree. The primary point being made in the evidence is that costs are likely to be more responsive to changes in TWh than to TW peak demand or the number of customers.

Historical tracking of the costs by business unit cannot be provided due to the merger and restructuring of the business units.

(ii) It is confirmed that the IESO's costs are not expected to change directly due to changes in the volume of electricity transmitted, given the volumetric changes that are currently anticipated.

HQEM-APPRO INTERROGATORY 33

Issues 2.2 and 2.3: Is the Methodology used to derive the proposed IESO Usage Fee of 1.13/MWh appropriate?

2-HQEM-APPrO-IR33

INTERROGATORY

Reference: Cost Allocation and Rate Design for the 2016 Fees of the IESO ("Elenchus Report"), Exhibit B-1-1, Attachment 3, p. 35. The evidence states that, "Unlike the transmission system itself, all of the IESO's costs are most logically associated with (or caused by) the energy throughput of customers."

(i) Please explain how the IESO's costs differ from transmission with respect to the relevance of the throughput of customers.

RESPONSE

(i) From a cost causality perspective, transmission costs are commonly considered to be caused by peak demand. In other words, transmission costs are incurred primarily to create the capacity necessary to accommodate the peak demand on the system. There is no obvious relationship between the IESO's total costs and the peak demand in the IESO-administered market or on the Ontario transmission grid. There is a closer relationship to the total energy (TWhs) on the system since the IESO's responsibilities relate primarily to managing the continuous balance of supply and demand on the system.

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HQEM-APPRO INTERROGATORY 34

Issues 2.2 and 2.3: Is the Methodology used to derive the proposed IESO Usage Fee of 1.13/MWh appropriate?

2-HQEM-APPrO-IR34

INTERROGATORY

Reference: Elenchus Study, Exhibit B-1-1, Attachment 3 and Exhibit B-1-2

(i) Please provide a sensitivity analysis developed or applied by Elenchus of the "Revenue to Cost Ratios" for changes in the following variables:

(a) Total demand forecast

(b) Export demand forecast

(c) Costs allocated to domestic consumers

(d) Costs allocated to export consumers.

RESPONSE

(i) Sensitivities for the identified variables were not developed or applied by Elenchus. Sensitivities of this type are not relevant to the determination of the appropriate cost allocation methodology although they may be relevant to consideration of whether the design of the IESO rates should be based on a cost allocation study. Also see HQEM-APPrO Interrogatory 23 (i), at Exhibit I, Tab 2.1, Exhibit 6.23 for a discussion of the sensitivities undertaken by Elenchus.

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HQEM-APPRO INTERROGATORY 35

Issues 2.2 and 2.3: Is the Methodology used to derive the proposed IESO Usage Fee of 1.13/MWh appropriate?

2-HQEM-APPrO-IR35

INTERROGATORY

Reference: Elenchus evidence Exhibit B-1-1, Attachment 3 of the IESO's 2016 revenue requirement submission page 19, line 5 shows that the allocation method for the IESO's NERC membership is split 50:50 between domestic and export.

(i) Please confirm that this is the only category that is split 50-50.

(ii) What is the justification for using this methodology? Why isn't a pro rata allocation by TWh more appropriate?

(iii) If Ontario had no exports, but maintained interconnections purely for short term reliability sharing purposes, wouldn't IESO still need to be a NERC member? If so, would it follow that under such circumstances domestic load would be the causal factor?

(iv) Can Elenchus advise how a NERC membership cost split based on TWh would affect the revenue-to-cost ratios and in turn the validity of the study?

RESPONSE

(i) Confirmed.

(ii) In Elenchus' view, NERC membership fees have two key drivers: access to the export market and as means of enhancing system reliability through international cooperation. The 50:50 allocation appeared to Elenchus to be more consistent with cost causality than a TWh allocation.

(iii) Elenchus does not accept that the incremental approach is an acceptable methodology to use in allocating costs. To do so would imply that no class should be allocated a share of common costs in excess of the incremental costs. Under that methodology, the principle of full cost recovery would be violated. To illustrate this point, it could equally be said that if Ontario had no need for cross-border reliability support, and interconnections were maintained purely for export sales, the IESO would still need NERC membership; hence, no costs should be allocated to domestic customers. The reality is that membership is required for both purposes, which is the reason Elenchus has used the 50:50 allocator.

(iv) If the NERC membership cost were allocated on the basis of TWh, the resulting revenue-to-cost ratios would be 96.46% for domestic customers, and 137.76% for export customers. Depending on the range of revenue-to-cost ratios selected by the Board, this may impact the selection of an appropriate rate design.

HQEM-APPRO INTERROGATORY 36

Issues 2.2 and 2.3: Is the Methodology used to derive the proposed IESO Usage Fee of 1.13/MWh appropriate?

2-HQEM-APPrO-IR36

INTERROGATORY

Reference: Elenchus evidence Exhibit B-1-1, Attachment 3 of the IESO's 2016 revenue requirement submission page 20, "Connections and Registrations?

(i) Is it reasonable to assume that domestic load would have more connections per TWh than exports?

(ii) If so, could this category be allocated pro rata by the number of connections and registrations, rather than by energy (TWh)?

(iii) How different would the resulting allocation be?

RESPONSE

(i) Although it is true that there are proportionally more connections related to Ontario-based facilities than inter-jurisdictional related facilities, it is not reasonable to distinguish these facilities on the basis of imports and exports. As described more fully in the response to Energy Probe Interrogatory 10c), at Exhibit I, Tab 2.0, Schedule 5.10, many of the facilities planned and built in Ontario benefit both domestic and export customers. The work of the IESO is influenced and performed for the benefit of both domestic and export customers, and it is incorrect to assume the work of the IESO is performed primarily for one group and then to attempt to parse out only the 'incremental' costs associated with a second group.

(ii) Mathematically, it is feasible. However, as stated above in part i), the IESO cannot distinguish between the number of connections and registrations on the basis of export versus domestic benefits, and so this calculation is not possible.

(iii) As described above in parts i) and ii), it is not possible to perform this calculation.

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HQEM-APPRO INTERROGATORY 37

Issues 2.2 and 2.3: Is the Methodology used to derive the proposed IESO Usage Fee of 1.13/MWh appropriate?

2-HQEM-APPrO-IR37

INTERROGATORY

Reference: Elenchus evidence Exhibit B-1-1, Attachment 3 of the IESO's 2016 revenue requirement submission page 26, "Stakeholder and Public Affairs".

(i) What benefit do exporters receive from Stakeholder and Public Affairs?

(ii) Has this benefit to exporters increased since the merger?

(iii) If exporters receive little to no benefit from this department, why should its costs be allocated in proportion to energy (TWh)?

RESPONSE

Parts i), ii) and iii)

Stakeholder and Public Affairs (S&PA) provides communications and stakeholder and customer support that is available to all market participants, including exporters. For instance, each week S&PA publishes the weekly bulletin, which provides news, events and change initiatives. S&PA staff also works to resolve market participant inquiries and questions on operational issues, as well as questions about IESO reports/data and access to IESO systems. This group receives several inquiries a week from exporters. Further, S&PA staff leads the IESO stakeholder engagement process and ensures that engagement principles are followed.

Since the merger, the IESO has moved forward with several engagements in which exporters have directly participated and which offer new opportunities for exporters in the IESO-administered markets. These include the Market Renewal initiative, Capacity Exports and Enabling System Flexibility. Exporters have also been actively involved in market rule amendments through the Technical Panel as observers and through the wholesaler/trader representative. Looking forward, the work streams within the Market Renewal project in particular portend to offer many new opportunities and potential benefit for exporters – such as the development of a financially-binding day-ahead energy market, further capacity trade and more frequent intertie scheduling.

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HQEM-APPRO INTERROGATORY 38

Issues 2.2 and 2.3: Is the Methodology used to derive the proposed IESO Usage Fee of 1.13/MWh appropriate?

2-HQEM-APPrO-IR38

INTERROGATORY

Reference: Elenchus evidence Exhibit B-1-1, Attachment 3 of the IESO's 2016 revenue requirement submission page 32 - 33, "Amortization".

(i) Is it true that amortization is based on assets that support all IESO departments?

(ii) If some departments are allocated entirely to domestic customers, does that mean that the allocation of all of the costs of the departments between domestic and export customers is going to be different from that derived from pro rata allocation of all costs?

(iii) Is it true that allocation of costs to exporters in total will be less than that derived from pro rata allocation of energy?

(iv) If amortization is based on assets that serve all departments, and not all department costs are allocated pro rata, shouldn't allocation of amortization be based on the proportion of total costs allocated to exporters, rather than pro rata based on energy?

RESPONSE

(i) No, in general IESO assets do not support all departments. See the discussion of IESO Assets in Appendix B of the Elenchus report.

(ii) Yes.

(iii) Yes, that is why the R/C ratio for the export class is > 100% under a common fee scenario. In that scenario, revenues are pro rata based on energy.

(iv) Amortization is not based on assets that serve all departments. Assets and amortization are predominantly associated with the Clarkson facility which is dedicated to managing the grid.

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HQEM-APPRO INTERROGATORY 39

Issues 2.2 and 2.3: Is the Methodology used to derive the proposed IESO Usage Fee of 1.13/MWh appropriate?

2-HQEM-APPrO-IR39

INTERROGATORY

Reference: EB-2010-0219 Report of the Board – Review of Electricity Distribution Cost Allocation Policy March 31, 2011, page iii

(i) In preparing its evidence for the IESO did Elenchus consider if improved cost allocations might be realized if revenue-to-cost ratios were closer to one as opposed to in the range of 0.8 – 1.2?

(ii) Can Elenchus comment on whether or not an increase in the IESO fee to the proposed $1.13/MWh from the status quo $0.803/MWh (an increase of 40%) is considered a significant shift in the rate burden for export customers relative to the status quo?

(iii) Was Elenchus mandated by the IESO to potentially prepare any mitigation measures for the shift in rate burden for the export customer class?

RESPONSE

(i) The revenue-to-cost ratio range that is approved by the OEB for the IESO will have no impact on the allocation of costs. It is the cost allocation methodology that generates the revenue-to-cost ratios. The revenue-to-cost ratio range is an independent factor that is determined as part of the rate design process. Rate design is informed by cost allocation.

(ii) Elenchus notes that cost allocation methodologies should not be results driven. It is generally accepted that cost should be allocated in a manner that is equitable based on the cost causality principle. It is rate design that takes into account rate impacts. The OEB expects distributors to use rate design to mitigate rate impacts where purely cost-based rates corresponding to allocated costs would result in rate shock.

(iii) Elenchus was not mandated by the IESO to prepare any mitigation measures for the shift in rate burden for the export customer class. Mitigation measures are addressed by rate design, not cost allocation.

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HQEM-APPRO INTERROGATORY 40

Issues 2.2 and 2.3: Is the Methodology used to derive the proposed IESO Usage Fee of 1.13/MWh appropriate?

2-HQEM-APPrO-IR40

INTERROGATORY

Reference: Cost Allocation Policy Review – Options and Preferred Alternatives prepared by Elenchus (October 15, 2010), page 41

(i) Does Elenchus continue to agree with the OEB 2010 Report that it is advisable to try to narrow the revenue-to-cost ratio range? Where is this addressed in Elenchus' evidence?

(ii) Does Elenchus agree with the stakeholder comments highlighted in the 2010 report in that a ratio above one would indicate that one customer class is subsidizing another?

(iii) In its recommendation to the IESO Elenchus concludes that "the revenue to cost ratios for the separate classes if a single usage fee is adopted would be 97.88% and 119.32% for the domestic and export classes, respectively" – can Elenchus confirm that it is recommending export customers subsidize domestic customers in Ontario?

(iv) In regards to the table on page 42 of its 2010 Cost Allocation Policy Review can Elenchus confirm that none of the distributors had General Service customers (50kW to 4,999kW) with a revenue-to-cost ratio equal to the highest limit range – in this case 120%?

RESPONSE

(i) The appropriate revenue-to-cost ratio range to be adopted by the OEB for purposes of designing the IESO's rates is a matter of rate design, not cost allocation. This issue is beyond the scope of the Elenchus Report in this proceeding.

(ii) No. Elenchus is of the view that any class that is within the Board-approved revenue-to-cost ratio range should not be considered to be either a source or recipient of a cross-subsidy. The point of a revenue-to-cost ratio range is that rates that result in within-range ratios are equitable and do not involve cross-subsidy; given the inherent imprecision of any cost allocation methodology – and the IESO cost allocation is highly imprecise for the reasons explained in the Elenchus report – the concept of full cost recovery cannot be limited to a revenue-to-cost ratio of 100%. Elenchus believes that it is this view that justifies across-the-board rate increases when all classes are within a Board-approved range.

(iii) No. Elenchus makes no recommendation regarding the revenue-to-cost ratio that is appropriate for the domestic and export class of the IESO should the Board determine that it is appropriate to establish separate domestic and export classes with allocated costs based on the cost allocation model developed by Elenchus. What Elenchus states is that if separate export and domestic classes are established with allocated costs based on the cost allocation model, and if the Board adopts a revenue-to-cost ratio range of 80% to 120%, it would then follow that if a common rate is adopted, export customers would not be considered to be subsidizing domestic customers in Ontario.

(iv) Confirmed, based on the information used to derive that table at the time.

HQEM-APPRO INTERROGATORY 41

Issues 2.2 and 2.3: Is the Methodology used to derive the proposed IESO Usage Fee of 1.13/MWh appropriate?

2-HQEM-APPrO-IR41

INTERROGATORY

Reference: EB-2012-0031, OEB Decision and Order dated June 6, 2013 regarding 2013 Export Transmission Service Rates states, page 4 and 5

(i) Can Elenchus confirm it provided evidence in EB-2012-0031 and that it recommended a separate rate class for exporters because of the reasons quoted above?

(ii) Given that exports are curtailable before domestic load, and that they therefore do not receive an equivalent service to the domestic service, please advise of the facts that Elenchus relies upon to support its position that it is now equitable to charge them as if they were receiving the same quality of service? Following on the citation in the reference to Interrogatory #13, what is the basis for Elenchus' current view that it is "equitable" to increase costs to a customer class that receives an inferior level of service?

(iii) Can Elenchus clarify then, that export customers, due to the fact that they may be curtailed by the IESO, actually provide reliability services to domestic customers? If export customers are being charged the same fee as domestic customers, how are export customers being compensated for the reliability service they provide?

RESPONSE

(i) Confirmed.

(ii) Elenchus does not accept that the identified differences in transmission service can be applied to the IESO services. The IESO is the system operator and as far as Elenchus is aware it does not operate the system differently for exporters as compared to domestic customers, other than the differences that are reflected in the cost allocation study which allocated the costs of some departments to domestic customers only. While transmission cost causality differs for firm and curtailable service, there is no reason to assume that the causality of IESO costs differs in a corresponding way for firm and curtailable service. To the extent that there may be a difference, Elenchus would suggest that curtailable service is likely to cause greater work effort for the IESO than firm service, given its uncertainty. This possible difference in the costs caused by firm domestic service and curtailable export service is not reflected in the IESO cost allocation model developed by Elenchus.

(iii) In reviewing each of the functions performed by the IESO departments that are included in the IESO cost allocation study, Elenchus is not aware of any departmental function that is, or can be, curtailed for export customers. The ETS rate recovers costs of services that can be curtailed.

HQEM-APPRO INTERROGATORY 42

Issues 2.2 and 2.3: Is the Methodology used to derive the proposed IESO Usage Fee of 1.13/MWh appropriate?

2-HQEM-APPrO-IR42

INTERROGATORY

Reference: Proceeding EB-2012-0031 "Hydro One Transmission 2013-2014 Revenue Requirement" Elenchus prepared a report for HQEM titled, "Ontario Cost Allocation and Export Tariff Service – October 1, 2012", page 4, line 23, page 5 line 3 and page 5, lines 15-17.

(i) Can Elenchus explain why its comments made in 2012 regarding lower rates for curtailable, or "interruptible" customers were not explored in the cost allocation study evidence it prepared in support of the IESO's 2016 revenue requirement submission?

(ii) Please confirm that with export customers at a revenue-to-cost ratio of 119.32% they are subsidizing domestic customers. If so, please advise why export customers should provide this subsidy other than the fact that the OEB tolerates temporary and unavoidable cross-subsidies among electricity distribution customers.

(iii) What is the amount of the subsidy in dollars per year that exporters will provide to domestic customers under this regime?

RESPONSE

(i) Please see the response to HQEM-APPrO-Interrogatory 41 at Exhibit I, Tab 2.1, Schedule 6.41.

(ii) Please see the response to HQEM-APPrO-Interrogatory 40 at Exhibit I, Tab 2.1, Schedule 6.40.

(iii) As indicated in the response to HQEM-APPrO-Interrogatory 40, if the revenue-to-cost ratio is within the Board-approved range, which has yet to be determined for the IESO, Elenchus does not accept that a cross-subsidy would exist. The amount of any cross-subsidy would be calculated by multiplying the percentage amount by which the revenue-to-cost ratio of a class exceeds the top end of the approved range by the total revenue. Under the scenario presented in the question, the top end of the approved range would not be exceeded.

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HQEM-APPRO INTERROGATORY 43

Issues 2.2 and 2.3: Is the Methodology used to derive the proposed IESO Usage Fee of 1.13/MWh appropriate?

2-HQEM-APPrO-IR43

INTERROGATORY

Reference: Proceeding EB-2012-0031, "Hydro One Transmission 2013-2014 Revenue Requirement" Elenchus prepared a report for HQEM titled, "Ontario Cost Allocation and Export Tariff Service – October 1, 2012", page 11, line 10 and page 12, line 2.

(i) Please provide the evidence and analysis that Elenchus relies upon to support treating domestic and export customers the same under the IESO 2016 fee proposal evidence when in 2012 it highlighted the inherent difference in the classes and proposed the creation of a separate and distinct rate class? Please advise if there have been market rule changes undertaken to treat exporters as firm load that has led to this change in position.

RESPONSE

(i) Please refer to the IESO's response to HQEM-APPrO-Interrogatory 41 at Exhibit I, Tab 2.1, Schedule 6.41.

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HQEM-APPRO INTERROGATORY 44

Issues 2.2 and 2.3: Is the Methodology used to derive the proposed IESO Usage Fee of 1.13/MWh appropriate?

2-HQEM-APPrO-IR44

INTERROGATORY

Reference: The Ontario Energy Board has stated the following with respect to applicants applying for retroactive rates: “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. In the future, the Board expects the Company to provide cogent evidence and rationale as to the reasons why rates should be retroactive” (RP-2000-0040, para.2.2.8).

(i) Please advise what evidence the applicant is relying upon to meet the Board’s expectations.

RESPONSE

The IESO has not sought retroactive rates in this application and believes it has met the Board’s requirement and expectations.

In December 2015 the IESO filed a request to have the then current fees made interim effective January 1, 2016 with the Board on December 16, 2015 and the Board issued its decision approving the request on December 22, 2015.

As required by legislation, the IESO filed its application with supporting evidence only after it received Ministerial approval of its 2016-2018 Business Plan. In its application filed on January 19, 2016 the IESO proposed that it file supplementary information on March 31, 2016, and that the interrogatory phase commence after this date, and this proposal was accepted by the Board. Additionally, and as stated in its January filing, the IESO consulted with several intervenors who were participants in the Settlement Conferences of the IESO's and OPA’s 2014 Revenue Requirement Submissions about scheduling the discovery process after it filed supplementary information and no intervenors were opposed to this approach.

The only comment counsel for HQEM-APPRO, has made with respect to the timing of any component of this application or on the processing of this application was made on April 12, 2016 by e-mail where he stated:

> *We are counsel for Hydro Quebec Energy Marketing. The IESO's proposed schedule suggests a settlement conference during the week of June 20, which is the week of St. Jean-Baptiste-Day in Quebec. As a result, my client is not available during that week. I appreciate that the schedule is still tentative so I would ask that the applicant and the Board take this into account and not schedule settlement conferences (where the client is expected to attend) during that period. Thank you*

HQEM-APPRO INTERROGATORY 45

Issue 2.5: What would be an appropriate effective date for the Usage Fees(s) approved within this proceeding.

2-HQEM-APPrO-IR45

INTERROGATORY

Reference: Exhibit B, Tab 1, Schedule 1, p. 7.

(i) Please identify how much domestic and export customers will either receive or pay if the Board approves the IESO's proposal on, for example, September 1, or December 1, 2016.

(ii) Given that the merger took place on January 1, 2015, please advise why the IESO did not bring a timely application for new fees in place for January 1, 2016.

RESPONSE

(iii) If the Board approves the IESO's proposal effective September 1, domestic customers would pay $8.7 million less than they otherwise would with the current IESO and OPA fees, and export customers would pay an additional $3.9 million. Similarly, if the IESO's proposal was implemented for December 1, domestic customers would pay $11.8 million less than they otherwise would with the current IESO and OPA fees, and export customers would pay an additional $5.4 million. It should be noted that the larger decrease in domestic payments is as a result of the IESO and OPA fees continuing to be charged separately, at the pre-merger rate, as per section 25.(9) of the *Electricity Act, 1998* ("Act"). The amount recovered under the existing fees is higher relative to the IESO's proposed 2016 fee, and domestic ratepayers currently contribute a larger overall proportion to the revenues as the OPA fee is not recovered from exporters.

	September 1 Implementation Date	**December 1 Implementation Date**
Change for domestic customers	-$8.7 M	-$11.8 M
Change for export customers	$3.9 M	$5.4 M

(iv) Section 25(1) of the Act requires that the IESO submit its proposed expenditure and revenue requirement 60 days before the beginning of each fiscal year, however the IESO is prevented from doing so until after the Minister approves the IESO's proposed business plan. 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 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. The IESO submitted a business plan for 2016 in line with the regular legislated process, and after receiving approval on December 9, 2015, began preparing the IESO's revenue requirement submission for filing with the OEB.

OEB STAFF INTERROGATORY 2

2.0 Usage Fee

2.2-Staff-2

INTERROGATORY

Reference: Exhibit B, Tab 1, Schedule 1, Table 2, Page 6

The IESO has provided a table that outlines the charge determinant calculation for the proposed 2016 usage fee.

(a) In order to allow OEB staff to verify the values used in this table, please provide the source (i.e. source publication and date) for each of the input variables (i.e. 18 month outlook demand forecast, transmission line losses, exports, and embedded generation).

RESPONSE

a) Ontario demand and embedded generation forecasts are derived from the IESO's 'Ontario Demand Forecast' created as part of development of the 18 Month Outlook and available at the following link: http://www.ieso.ca/Pages/Participate/Reliability-Requirements/Forecasts-&-18-Month-Outlooks.aspx. The charge determinants are based on the September 21, 2015 demand forecast. A forecast of export volumes is created by the IESO for the purpose of its revenue requirement submission. Export forecasts are a rolling three year average by month, adjusted for unusual market conditions. Transmission line losses are calculated at 2.2%.

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OEB STAFF INTERROGATORY 3

2.0 Usage Fee

2.3-Staff-3

INTERROGATORY

Reference: Exhibit B, Tab 1, Schedule 2, Page 3 of 4

The IESO does not believe a traditional cost allocation model is appropriate for the IESO as 1) there is a lack of cost causality between the model and the operations of the IESO and 2) all the costs for the IESO had to be allocated by department based strictly on judgment rather than based on the customer class the assets served.

(a) Given that the IESO believes that a standard cost allocation approach is not suitable for its purposes, did the IESO consider other alternatives? If other alternatives were considered, please provide the reasons for not considering these options. If other alternatives were not considered, please explain why.

RESPONSE

From the start, the IESO has stated that it believes that the proposal to move to one fee for the organization should be accepted on its own merits, without necessitating a cost allocation study (see Exhibit B-1-1). Nonetheless, the IESO hired Elenchus to develop a cost allocation model to specifically address the Board's decision in the OPA's 2011 Revenue Requirement Submission.

The IESO came to realize the specific deficiencies with the cost allocation study with respect to the IESO when the Elenchus model was rerun to include 2016 financial information. As described at Exhibit B-1-2, page 2, sensitivity to year over-year changes in forecast energy volumes illustrated that the cost allocation model used by Elenchus does not produce robust results for the IESO.

Given the timing of this realization, it was not possible for the IESO to develop alternatives to the standard cost allocation approach.

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OEB STAFF INTERROGATORY 4

2.0 Usage Fee

2.4-Staff-4

INTERROGATORY

Reference: Exhibit B, Tab 1, Schedule 1, Page 7

The IESO proposes to charge both the IESO and OPA interim usage fees to the same pools of market participants the OEB approved them to be charged until the end of the month in which the OEB approval is received for the 2016 usage fee. The IESO then proposes to charge (or rebate to) market participants the difference between the 2016 IESO usage fee approved by the OEB and the interim usage fee(s) they paid, if any, based on their proportionate quantity of energy withdrawn, which may include scheduled exports and embedded generation, in 2016. The IESO noted that any such charges (or rebates) will be provided in the next billing cycle following the month in which OEB approval is received.

(a) Please provide range (min/max) of impacts on market participants as at December 31, 2016. If possible please provide the ranges separately for domestic and export. Please also provide a description of the approach and assumptions used to estimate the impacts.

RESPONSE

** OEB Staff confirmed that the date range in question (a) is from January 1, 2016 to December 31, 2016.*

(a)

		OPA	**IESO**	**Proposed IESO Fee**
2016 Demand[1] (TWh)	Domestic[2]	135.6	135.6	135.6
	Embedded Generation	-	6.6	6.6
	Exports	-	17.9	17.9
	Total	135.7	160.1	160.1
Fee ($/TWh)		.438	.803	1.13
Total Revenues Generated (M)		$59.44	$128.56	$180.91
Proportion of Revenues paid by exporters ($M)		-	$14.37	$20.23
Proportion of Revenues paid by domestic customers ($M)		$59.44	$114.27	$160.80[3]
		Total: $173.71		

1. Demand forecast source is 18 month outlook issued September 21, 2015, consistent with original IESO filing on January 19, 2016.
2. Comprised of allocated quantity of energy withdrawn (AQEW) minus line losses of 3.1 TWh
3. Includes embedded generation

The current IESO fee of $0.803/MWh is charged to exports, embedded generation and Ontario demand, and these three components are forecast to total 160.1 TWh in 2016. The OPA fee of $0.438/MWh is charged to only Ontario withdrawals, which is forecast to be 135.7 TWh for 2016. The IESO is proposing to charge the single fee to the same base the current IESO fee is charged to, therefore 160.1 TWh at $1.13/MWh.

As illustrated in the table above, the range for exports is $20.23 million in 2016 with the proposed IESO fee vs $14.37 million with the current IESO fee.

The range for domestic customers is $160.80M with the proposed IESO fee vs $173.71 million under the current fees.