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July 8, 2022

Delivered by Email & RESS

Ms. Nancy Marconi, Registrar
Ontario Energy Board
P.O. Box 2319, 27th Floor
2300 Yonge Street
Toronto, ON M4P 1E4

Dear Ms. Marconi:

Re: Generic Proceeding on UTR-Related Issues and the Export Transmission Service ("ETS") Rate
Power Advisory Interrogatory Responses
OEB File No.: EB-2021-0243

We are counsel to the Association of Power Producers of Ontario ("**APPrO**") in the above-noted proceeding (the "**Proceeding**").

Pursuant to the OEB's Procedural Order No. 2, enclosed please find interrogatory responses from Power Advisory LLC ("**PA**") in respect of their "Expert Report for the market impacts of changes to the ETS Rate" filed May 27, 2022 in respect of the Proceeding (the "**PA Report**").

1. **Expertise of Power Advisory LLC**

In its Decision on Expert Evidence and Procedural Order No. 2 issued April 1, 2022, the OEB accepted APPrO's proposed expert evidence and made the following determination:

> "APPrO has stated that Mr. Lusney and Mr. Yauch have considerable expertise in energy market analysis, regulatory affairs, generation development, system planning, market assessment and energy policy analysis. **The OEB is prepared to accept both Mr. Lusney and Mr. Yauch as experts in energy market and energy policy analysis for this evidence, and will proceed on that basis.** It is not clear whether Mr. Lusney or Mr. Yauch are experts in regulatory affairs, but the OEB concludes this is not required for this evidence. Previous appearances before a regulatory tribunal provide helpful experience in regulatory affairs, but do not necessarily qualify a person as an expert in the field."

This determination was somewhat unusual in its timing (occurring before APPrO had asked to qualify its proposed experts in any particular area) and its basis (it was made on the basis of APPrO's May 24, 2022 proposal to file expert evidence only).

Traditionally, a party's request to qualify an expert would accompany the actual expert evidence. That way the request to qualify the expert can be crafted to only encompass those areas that are relevant and necessary for their actual expert evidence.

While APPrO has endeavoured to work within the confines of OEB's original determination as set out in PO#2, it is now clear that at least one party is considering challenging PA's expertise in the area of "cost allocation".[1]

The CVs for Mr. Lusney and Mr. Yauch are attached to their Report. A brief review of these CVs demonstrates they have the considerable expertise in cost allocation, including:

- Mr. Lusney was accepted as an expert witness on transmission planning and cost allocation by the Alberta Utilities Commission during a Transmission Rate Tariff hearing.

- Mr. Yauch provided expert evidence as part of a Tax Court proceeding on the cost allocation and bill design of Ontario's electricity sector.

- Mr. Lusney supported a consortium of clients the analysis of substation cost allocation for potential cost sharing between distributed connected generation and load customers within a distribution network in Alberta in response to the AESO pursuit of sub-station fractioning.

- Mr. Yauch has acted as a consultant for regulatory hearings at the OEB since 2013, engaging on a wide range of topics including cost allocation.

- Mr. Yauch designed a cost allocation model for an LNG plant in Northern Ontario based on the OEB's Cost Allocation Model (CAM).

In this context, APPrO submits that Mr. Lusney and Mr. Yauch should be accepted as experts in cost allocation (in addition to the areas of expertise already accepted in PO#2).

2. Concerns around Lack of Coordination

Pursuant to Procedural Order No. 2, the OEB expressly noted its expectation "that intervenors representing the same interests or class of persons will make efforts to coordinate their interrogatories in this proceeding."

APPrO acknowledges the efforts of CME, CCC and VECC to coordinate their interrogatories as representatives of consumer interests that do not pay the ETS rate. However, it is not clear what steps (if any) EP, SEC, LPMA, and AMPCO took also coordinate their interests given their nearly identical interests.

APPrO has taken considerable effort to coordinate its intervention with numerous parties representing similar interests. The OEB expects this because it facilitates the efficiency of the OEB's adjudicative process.

[1] See PA-VECC-1.0.

APPrO believes it is reasonable to expect that other parties would put in a similar level of effort to coordinate participation amongst all consumer interests that do not pay the ETS rate, which includes EP, SEC, LPMA, AMPCO, VECC, CCC and CME.

Please do not hesitate to contact the undersigned if you have any questions.

Yours very truly,

BORDEN LADNER GERVAIS LLP

J Vellone

Per: John Vellone

cc: Brady Yauch and Travis Lusney, Power Advisory LLC
David Butters, APPrO
Parties in EB-2021-0243

ONTARIO ENERGY BOARD

IN THE MATTER OF the *Ontario Energy Board Act, 1998, S.O. 1998*, c. 15 (Sched. B), as amended (the "OEB Act").

AND IN THE MATTER OF a Generic Hearing on Uniform Transmission Rates Related Issues and the Export Transmission Service Rate.

POWER ADVISORY LLC

RESPONSES TO INTERROGATORIES

Filed: July 8, 2022

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RESPONSE TO INTERROGATORIES FROM OEB STAFF

PA-Staff-1

Ref.: Power Advisory Report / p. 9 / paragraph 18

Preamble

Power Advisory states on page 9: "export traders pay congestion rents that are used to offset a portion of transmission-related costs."

Question(s)

a) Please explain whether and how transmitters receive congestion rents. If they do not, please clarify the statement above that congestion rents are used to offset a portion of transmission-related costs — by whom and how?

Response:

a) Under the *Ontario Energy Board Act, 1998,* a "transmitter" is a person who owns or operates a transmission system.

Consistent with the requirements imposed by the OEB under an electricity transmission license, all licensees are required to enter into an operating agreement with the IESO providing for the direction by the IESO of the operation of the licensee's transmission system. The IESO operates the bulk transmission assets in Ontario and thus is a "transmitter" under Ontario law. As part of its function as the operator of the bulk transmission assets the IESO collects, inter alia, congestion rents that should, if done properly, be accounted for in the allocation of the costs associated with the bulk transmission system.

The IESO receives congestion rents, which are then distributed to market participants based their proportionate share of transmission service charges paid. Congestion rents are collected in the Transmission Rights Clearing Account (TRCA). According to the Market Rules Chapter 8, section 4.18: "Subject to section 4.18.3, the IESO Board may, at such times as it determines appropriate, authorize the debit of funds from the TR clearing account in accordance with section 3.6.3 of Chapter 9 ***for the purpose of using those funds to offset transmission services charges*** (emphasis added)." Further, Chapter 9, 4.71, states: "Disbursements from the TR clearing account ordered by the IESO Board pursuant to section 4.18.2 of Chapter 8 shall be distributed among market participants based on the proportionate share of all transmission service charges paid during energy market billing periods immediately preceding the current energy market billing period, in accordance with this section 4.7." In the past the TRCA was disbursed based on proportionate energy volumes, but this was recently changed based on analysis by the Market Surveillance Panel (MSP).

PA-Staff-2

Ref.: Power Advisory Report / p. 10 / paragraph 22

Preamble

The Power Advisory Report (Report) states that "All of the evidence in this proceeding is clear that export customers do not impose a cost on Ontario's electricity grid."

Question(s)

a) Please explain and clarify that export customers' use of the Ontario electricity grid does not impose any short-term or long-term congestion, nor any operations, maintenance, administration, or capital costs on it.

Response:

a) Exports buy from the pool of generation resources, therefore it is impossible to allocate internal system congestion (short-term or long-term) to exports. Congestion on the interties are caused by exports, but they are only competing with themselves (i.e., exports congesting other exports). Power system planning does not consider export capacity as part of resource adequacy and reliability objectives, so there are very limited capital costs. As part of overall scheduling, dispatch, maintenance coordination and administration exports may participate; however, their use of the system is secondary to the primary objective of serving internal Ontario load. Further, the facilities that exports use are also used by imports to meet internal electricity demand, the higher priority. Without exports, the operations, maintenance, and administration costs would be very close to the same in Power Advisory’s opinion. Additionally, if internal constraints limit the ability to move energy through the interties, exports are curtailed.

PA-Staff-3

Ref.: Power Advisory Report / p. 10 / paragraph 23

Preamble

Power Advisory states "The financial impact to Ontario ratepayers from increasing the ETS rate to $6.54/MWh would have been a net increase in costs of $42.6 million over the 2018-2021 timeframe" (emphasis added).

The second heading in Table 1 states "Increasing ETS Rate to $4.69/MWh" (emphasis added).

Question(s)

a) Please confirm whether the second heading in Table 1 should read as "Increasing ETS Rate by $4.69/MWh" (from $1.85/MWh for a total ETS rate of $6.54/MWh). Otherwise, please clarify.

b) Please confirm whether the estimated $42.6 million is an annual total in each of 2018, 2019, 2020 and 2021 or whether it is a cumulative total over the period 2018 through 2021.

c) What was the approximate total ratepayer cost over the 2018-2021 timeframe and approximately what proportion of that does $42.6 million represent?

d) Has Power Advisory conducted sensitivity analyses of this result? If no, why not? If yes, please summarize key findings of the sensitivity analysis.

e) To what variables is the estimated $42.6 million figure most sensitive and in which direction?

Response:

a) Confirmed.

b) It is the cumulative total over the 2018 – 2021 time period.

c) The UTR amounts for 2018 alone totalled more than $1.6 billion. Wholesale market related costs typically total more than $19 billion annually. In any case, the benefits and costs described here as part of changing the ETS rate are well below 1% of total system costs, however they are defined. That said, and as explained in our evidence, the ETS rate issue will have a material impact on the competitiveness of Ontario exports and the ability of exporters to create incremental value for all Ontario consumers.

d) Power Advisory has not conducted a sensitivity analysis of this result. The results are based on historical data and how export transactions were impacted by various market prices.

e) Congestion rents will be highly sensitive to the ETS rate, with a higher rate likely leading a to direct reduction in congestion rents. The impact would be most noticeable on interties where price spreads are tightest (i.e. New York).

PA-Staff-4

Ref.: Power Advisory Report / p. 10 / Table 1

Preamble

Table 1 of the Report indicates the financial impact of increasing and decreasing the ETS rate. The impact of increasing the ETS rate is shown as a decrease in congestion rent of $169.0 million from 2018 to 2021 and the impact of lowering the ETS rate is shown as an increase in congestion rent of $111.0 million from 2018 to 2021.

Question(s)

a) Please explain how much of the estimated change in congestion rent would flow to transmission rights holders versus Ontario ratepayers. If less than a full share of the change would flow to Ontario ratepayers, please clarify why that value was not used in the Table 1 instead.

b) Please break down the decrease in congestion rent under the "Increasing ETS Rate to $4.69/MWh" scenario in Table 1 into allocated Congestion Rents received from the Market, TR Auction Revenue, TR Payments to Rights Holders and Transmission Rights Clearing Account Disbursements to Ontario Ratepayers. Please update the Benefit to Ontario Ratepayers in Table 1 based on Transmission Rights Disbursements to Ontario Ratepayers instead of Congestion Rents.

c) Please break down the increase in congestion rent under the "Lowering ETS Rate to $0/MWh" scenario in Table 1 into allocated Congestion Rents received from the Market, TR Auction Revenue, TR Payments to Rights Holders and Transmission Rights Clearing Account Disbursements to Ontario Ratepayers. Please update the Benefit to Ontario Ratepayers in Table 1 based on Transmission Rights Disbursements to Ontario Ratepayers instead of Congestion Rents.

Response:

a) Congestion rents accrue to the Transmission Rights Clearing Account (TRCA). The IESO then debits money from the TRCA to Transmission Rights (TRs) holders, including any shortfall in TR-related payments. Once this has occurred, the IESO debits amount used to offset transmission service charges. The process is described in detail in Market Rules, Chapter 8, section 4.18. The IESO recently changed distribution from the TRCA so that funds distributed are based on total transmission service charges paid, rather than on total transmission volumes (the previous methodology). An increase in the ETS will increase transmission service charges paid by exporters and, subsequently, increase their allocation of disbursements from the TRCA. Under the current methodology of TRCA disbursements, nearly 98% of disbursements flow to Ontario ratepayers.

b) The analysis completed by Power Advisory does not include TR Payments to holders of TRs. Given the short time frame and lack of easily accessible data, Power Advisory cannot undertake this analysis. In any case, in an efficient market, the value of TRs would exactly equal avoided congestion rents. As an example, if the value of TRs in one year were $100 million in the IESO auction and that resulted in a $100 million in avoided congestion rent, $100 million would flow to the TRCA. The Market Surveillance Panel has published multiple analyses on the IESO's operation of the TR market and whether is has been operated efficiently. The analysis conducted by Power Advisory calculated the reduction in congestion rents based on HOEP – using a higher HOEP as a proxy for an increased ETS charge.

c) See the previous answer.

PA-Staff-5

Ref.: Power Advisory Report / p. 13 / paragraph 35
Power Advisory Report / p. 10 / paragraph 23
Power Advisory Report / p. 10 / Table 1

Preamble

Power Advisory states on page 13: "The updated ETS rate, based on Elenchus' cost allocation methodologies, would increase the ETS rate to \$3.66/MWh to as much as \$6.54/MWh — potentially a nearly four-fold increase from its current level.

Power Advisory states on page 10: "The financial impact to Ontario ratepayers from increasing the ETS rate to \$6.54/MWh would have been a net increase in costs of \$42.6 million over the 2018-2021 timeframe".

Table 1 on Page 10 summarizes Power Advisory's analysis of the "Financial Impact" of an increase of the ETS rate to \$6.54/MWh.

Question(s)

a) Please provide an estimate of the financial impact to Ontario ratepayers from increasing the ETS rate to \$3.66/MWh. If possible, please provide the results in the same format as Table 1 on Page 10 of Power Advisory's report.

b) Please provide an estimate of the financial impact to Ontario ratepayers from increasing the ETS rate to \$5.42/MWh. If possible, please provide the results in the same format as Table 1 on Page 10 of Power Advisory's report.

Response:

a) This request requires Power Advisory to conduct significant work and would not significantly clarify the current analysis. As such, Power Advisory is not able to provide the requested information with reasonable effort, given the current timelines and amount of interrogatories. We can say that the relationship is approximately linear. If the proposed increased in the ETS is half of what was modelled in our analysis, we would expect the net cost to Ontario ratepayers to be, to a large extent, half of what was included in our analysis. In any case, our analysis shows that lowering – not increasing – the ETS provides better value for Ontario ratepayers.

b) See previous response.

PA-Staff-6

Ref.: Power Advisory Report / p. 11 / paragraph 24

Preamble
Power Advisory states on page 11: "The value of energy exports in the current electricity grid — which is now largely a fixed cost system — is vastly different than when the ETS rate was initially set in the early 2000s and into the last decade...."

Question(s)
a) Please explain what is meant by "the value of energy exports".
b) Please explain what is meant by a "fixed cost system", and the significance of this.
c) Please explain what the electricity grid was previously and the significance of this to setting the ETS rate in contrast to the current electricity grid.
d) Please explain how and why the value of energy exports has changed since the ETS rate was initially set up to the present.

Response:
a) Value refers to the ability to receive revenue to partially offset the fixed costs of the supply costs of the Ontario system (for Ontario ratepayers) through exports to neighbouring jurisdictions. This value is highest under unforeseen abnormal conditions (e.g., financial crisis 2007/2008, Covid-19 of 2020-2022) that requires immediate action by market participants to address short-term inefficiencies in the wholesale electricity market. The value of exports is higher when the grid is largely a fixed cost system, as is largely the case in Ontario.
b) Almost all supply resources in Ontario are contracted by the IESO or under rate-regulation under the OEB (i.e., OPG generation assets). The contracted supply resources receive top up payments beyond market revenue to recover fixed costs and certain variable costs. The market revenue from wholesale market participation and top-up payments collected through Global Adjustment means Ontario ratepayers effectively pay the same amount regardless of market conditions (i.e. wholesale market prices). In 2021, GA payments represented the majority of total wholesale costs.
c) At market opening in 2002, it was expected that generation resources would compete in the wholesale market or sign bilateral contracts to earn revenue and remain economically viable. Under that assumed competitive framework, total system costs paid by Ontario ratepayers would fluctuate – as demand increased and new resources were added, so too would the total system cost. As demand decreased (and prices declined) so too would the cost of the system as resources were retired, mothballed or not dispatched in the wholesale market. The most efficient market participants would remain in operation, while the least efficient market participants would exit the market. The current hybrid market framework largely divorces system costs from supply and demand dynamics and long-term competition. As demand declines (or supply increases), total system costs in the medium-term (or even in the long-term, as has been experienced over the last decade) do not change materially. For example, if demand declines and supply increases, prices would be expected to fall and high-cost generators would be expected to retire or mothball – overall system costs would subsequently decline. The opposite occurred in

Ontario over the last decade, with demand declining (or plateauing), supply increasing and overall system costs increased due to the lack of retirement of unneeded supply.

d) See b) and c)

PA-Staff-7

Ref.: Power Advisory Report / p. 9 / paragraph 17
Power Advisory Report / p. 15 / paragraph 42

Preamble
Power Advisory states on page 15: "The IESO's analysis expects that any increase in revenue from a higher ETS will be fully offset by a decrease in revenue from congestion rents".
Power Advisory states on page 9: "All else being equal, increasing the ETS rate increases the transactional cost of exporting energy from Ontario".

Question(s)

a) Please clarify how increasing the ETS rate increases transaction costs for exporting energy from Ontario and why this might cause a reduction in revenue from Congestion Rent.

Response:

a) Each exporter needs to be pay fixed charge (the ETS rate) to export energy from Ontario. The cost of the ETS would be expected to be included in their bids – i.e. the value of exporting energy from Ontario to a neighbouring jurisdiction would consider all three of the HOEP (or PD-1), congestion rent and the ETS charge. As the ETS charge increases, a corresponding decrease would be expected in export volumes that clear, with the lower volumes resulting in reduced congestion rents. A higher ETS may also require a greater spread between jurisdictions, which may result in a lower bid in Ontario. Lower bids reduce congestion rent.

PA-Staff-8

Ref.: Power Advisory Report / p. 15 / paragraph 42

Preamble

Paragraph 42 in the Report states that "A reduction in congestion rent will reduce disbursements from the Transmission Rights Clearing Account (TRCA), which are used to reduce the overall revenue requirement for Network transmission costs paid by all Ontario ratepayers."

Question(s)

a) Please explain how TRCA disbursements are applied to Network transmission costs paid by Ontario ratepayers.
b) Please describe in detail how Congestion Rents received from the Market, TR Auction Revenue and TR Payments to Right Holders flow to Ontario end-use customers including the dollar amount for class A, class B and low-volume customers and any differences.
c) Please describe how ETS revenue flows to Ontario end-use customers. including the dollar amount for class A, class B and low-volume customers and any differences.
d) Please compare and contrast how the various streams of revenue from exports in the responses to question b) and c) flow to the benefit of Ontario end-use customers.
e) Please provide the reduction in Congestion Rents received from the Market, TR Auction Revenue and TR Payments to Right Holders if the ETS rate is increased to $6.54/MWh.
f) Please provide the increase in Congestion Rents received from the Market, TR Auction Revenue and TR Payments to Right Holders if the ETS rate is decreased to $0.00/MWh.
g) Please provide the reduction in Congestion Rents received from the Market, TR Auction Revenue and TR Payments to Right Holders if the ETS rate is increased to $3.66/MWh.

Response:

a) Power Advisory assumed that the accounts from the TRCA, which according to the Market Rules are distributed to "market participants based on the proportionate share of all *transmission service charges* paid during energy market billing periods" would be allocated fully to network service charges, which are defined as the "transmission service relating to the use of the IESO-controlled grid for the transmission of energy and ancillary services, other than in respect of transactions to which export transmission service relates." Transmission service charges can also mean "any one or more of network service, export transmission service, line connection service, transformation connection service and such other service as may be approved by the OEB." In any case, funds from the TR would be used to offset transmission-related costs approved by the OEB.
b) The process for clearing funds from the TRCA are described in detail in the Market Rules Chapter 9, section 4.7. Power Advisory did not analyze how the funds would be distributed to Class and Class B market participants. In short, the TRCA collects revenues from the TR Auction and net congestion rents (i.e. those left over after payments are made to).
c) See b).
d) Congestion rents occur on the intertie and are collected by the IESO in the TRCA. TR Auction revenues are also captured in the TRCA. TR holders are provided payments to offset congestion costs, with these funds subtracted from the TRCA. Any money that remains in the TRCA after TR holders have been made whole for congestion rents paid

then flows to Ontario customers to offset transmission costs (this is a simplified process of the TRCA, as described in the Market Rules).

e) Power Advisory did not undertake a detailed review of the TR Auction and interchange between auction revenues, payouts and congestion rents. The analysis focused on congestion rents and market prices, as hourly data was publicly available. TR Auction and Payment data is made public on a monthly basis, but is not easily captured. In any case, as described repeatedly, TR Auction Revenue and Congestion Rent should net out one another in a perfectly efficient market.

f) This request requires Power Advisory to conduct significant work and would not significantly clarify the current analysis. As such, Power Advisory is not able to provide the requested information with reasonable effort, given the current timelines and amount of interrogatories. While the IESO publishes data from the TRCA, it is done on a monthly basis and not easy to compile quickly.

g) See previous answer.

PA-Staff-9

Ref.: Power Advisory Report / p. 15 / paragraph 45

Preamble

Power Advisory states that "Ontario's dynamic design for determining congestion rents is not replicated in other markets and — given how material congestion rents have been in recent years — understates the true cost (and value to Ontario ratepayers) of exporting energy from Ontario into neighbouring jurisdictions."

Question(s)

a) Please clarify if Power Advisory is saying that Ontario's intertie pricing design systematically undervalues the benefits of exporting energy from Ontario? If so, please explain, otherwise, please clarify the statement.

Response:

a) No. What is meant is that the $1.85/MWh ETS charge is not reflective of the actual cost of exporting energy from Ontario, given the dynamic price set at the intertie. In many hours – and on particular interties – the actual cost of exporting energy is materially higher due to congestion rents.

PA-Staff-10

Ref.: Power Advisory Report / pp. 16-17 / paragraph 49
Power Advisory Report / p. 37 / paragraph 90

Preamble

Power Advisory states on pages 16-17:

> "applying principles of the pole attachment charges to exports is inappropriate, since their use of delivery assets are different. Pole attachment charges are for consistent access and use of fixed assets (in this case utility poles used by telecommunication companies). [...] Conceptually, this can be the same as purchasing a fixed amount of transfer capacity on a transmission line. Exports, on the other hand, do not make long-term fixed commitments to capacity on transmission infrastructure. Instead, exports use the system when an economic opportunity exists. This "opportunity service" targets excess capacity in the system that is being inefficiently used by existing domestic demand. [...] Any cost allocation methodology should recognize the economic opportunity nature of exports and that exports do not purchase a fixed amount of capacity from the system."

Power Advisory states on page 37:

> "The reason for a near steady-state of exports is a combination of factors. First, export volumes include wheel through transactions, which are a simultaneous import and export of energy — (a trader offers an equivalent amount of imports and exports in the same hour). Second, export trades may be done on an uneconomic basis when they are part of a long-term contractual agreement, as discussed previously."

Question(s)

a) Please clarify whether traders acting under long-term contracts are "opportunity traders" or are they demonstrating a greater commitment to the infrastructure?

b) Is it Power Advisory's view that it would be appropriate to allocate some shared costs to long-term contract traders but only incremental costs to "opportunity traders"?

c) Does Power Advisory consider the Elenchus 2014 Methodology an appropriate cost allocation methodology that recognizes the economic opportunity nature of exports? Why or why not?

Response:

a) Commitments for supply in other jurisdictions by exporters does not demonstrate a greater commitment to infrastructure because exporters can fill the supply needs using resources in other jurisdictions (or competing resources internal to their market). An export's profitability is primarily determined by finding the cheapest supply resource to meet contractual requirements. To the best of Power Advisory's knowledge, no exporter has long-term transmission capacity commitments on the Ontario intertie.

b) No, long-term contract traders and opportunity traders are the same type of entity in Ontario's market design when considering intertie transmission assets.

c) A methodology that allocates costs of assets dedicated to export customers is more appropriate in our view. In any case, a strict cost allocation exercise does not fully account for the value that a dynamic export market provides for Ontario ratepayers, nor does it account for the revenues paid by exporters through the TR auction and congestion rents.

PA-Staff-11

Ref.: Power Advisory Report / p. 17 / paragraph 50

Preamble:

Power Advisory states: "A cost-benefit analysis should be assessed when determining cost allocation to secondary users of the transmission system."

Question(s)

a) Please explain what is meant by "secondary users of the transmission system".

b) Please explain what Power Advisory considers an appropriate cost-benefit analysis methodology to determine cost allocation to secondary users of the transmission system.

Response:

a) Power System Planning does not consider the needs or economic opportunities of exporters when planning, designing, and constructing the Ontario power system (e.g., there is no internal transmission line being developed under IESO guidance for exporters). Further, exports are curtailed in favour of internal Ontario demand during tight supply conditions. The IESO explicitly states in its evidence that it does not plan the system to include exports.

b) At a high level, the current opportunity service modernization underway in Alberta is a good example of reassessing an appropriate tariff for exports. Any cost/benefit analysis would clearly detail what (if any) cost export customers introduce in Ontario, while clearly detailing the benefits, which could include financial and operational benefits.

PA-Staff-12

Ref.: Power Advisory Report / p. 21 / paragraph 58

Preamble

In this paragraph Power Advisory quotes OPG's estimate of its marginal cost of production from hydro facilities of $14.40/MWh where the marginal costs are driven by water rental fees and property taxes. About 3,000 MW of hydro supply continues even at market prices as low as zero due largely to "must-run" restrictions. Power Advisory states that this is an economic inefficiency that arises due to the hybrid design of the electricity market and surplus baseload generation.

Question(s)

a) Does the marginal cost of $14.40/MWh represent the cost of real resource inputs into the production of hydro that are used up in the process and therefore unavailable for other uses? Examples of real resource inputs would be labour costs, the cost of station service electricity, or, in the case of a gas-fired generator, the cost of fuel used. Or, do these marginal costs represent a simple transfer from OPG to the recipients of water rental fees and property taxes? Please explain how Power Advisory arrives at answers.

b) If the marginal cost of $14.40/MWh is a simple revenue transfer and does not reflect the use of real productive resources, is it correct to say that hydro production is inefficient if the price of electricity is zero? Why or why not?

c) If the $14.40/MWh marginal cost does in fact represent the cost of real resources used in the production process, does the fact that the hydroelectricity is produced on a "must-run" basis have any bearing on the efficiency or inefficiency of the hydroelectric production? Why or why not?

Response:

a) The $14.40/MWh marginal cost referenced in the Power Advisory report is taken from Ontario Power Generation’s (OPG) most recent rate application, EB-2020-0290, Exhibit A1-11-1, Attachment 1, page 14. The marginal cost represents a real cost of a fuel input used by hydroelectric generators – OPG and others – and should not be viewed as a “simple transfer from OPG” to taxpayers (i.e. the public). The fuel cost for hydroelectric generators should be viewed no differently than that of gas-fired or other generators with a non-zero cost fuel input.

b) Power Advisory does not consider the $14.40/MWh a “simple transfer”. The marginal cost paid by hydroelectric generators is the cost of fuel, which is set by the province as a result of water being a public resource. The cost should be viewed no differently that the cost of natural gas or other fuel inputs. If the Market Clearing Price (MCP) $0/MWh in a given hour, it would be insufficient to fully recover input costs in that hour.

c) The must-run nature of hydroelectric generation can include a number of variables, particularly safety, environmental and reliability concerns.

PA-Staff-13

Ref.: Power Advisory Report / p. 29 / paragraph 72

Preamble

Power Advisory states that "In a perfectly efficient market, congestion rents either accrue to ratepayers or are used to fund transmission expansion — essentially, funding an economic buildout of intertie capacity."

Question(s)

a) Please confirm whether congestion rents are used to fund transmission expansion in Ontario. If not, why not?

b) Does Power Advisory propose that congestion rents should be used to fund transmission expansion In Ontario? Please explain the reason for Power Advisory's position.

Response:

a) We are not aware of any congestion rents being used to fund transmission expansion in Ontario.

b) If export and domestic customers view the benefits of transmission expansion as more valuable than rebates of congestion rents, then yes. If not, then no.

PA-Staff-14

Ref.: Power Advisory Report / p. 34 / paragraph 82
Submissions on the ETS Rate / Attachment 3 / page 12 of 17

Preamble
Power Advisory states on page 34 that "Higher intertie prices result in greater congestion rent that will accrue to Ontario ratepayers — even with some congestion rents being avoided as a result of Transmission Rights (TRs), which act as a hedge against congestion rent."
The IESO in its Submission on the ETS Rate notes that:

> "These market design changes mean the vast majority of funds disbursed through the TRCA reduce transmission costs for domestic consumers. Further, it should be noted that the dynamic nature of the ICP and design changes made to the TRCA are aligned with wider IESO initiatives, including the Market Renewal Program".

Question(s)
a) Please provide Power Advisory's comments on the expected impacts of the Market Renewal Program (MRP) on Congestion Rents received from the Market, TR Auction Revenue, TR Payments to Right Holders and avoided Congestion Rents.
b) Please provide a forecast of Congestion Rents received from the Market, TR Auction Revenue, TR Payments to Right Holders and avoided Congestion Rents from 2023 to 2027 excluding the future impact of the IESO's MRP.
c) Please provide a forecast of Congestion Rents received from the Market, TR Auction Revenue, TR Payments to Right Holders and avoided Congestion Rents from 2023 to 2027 including the future expected impact of the IESO's MRP.
d) Please explain how and from whom is the shortfall paid if the payouts from Transmission Rights sold to Rights Holders exceed the Congestion Rents received from the Market.
e) What is the volume of Transmission Rights sold to Rights Holders that exceeded the volume of Congestion Rents received from the Market from 2017 to 2021?
f) What is the dollar value of Transmission Rights sold to Rights Holders that exceeded the dollar value of Congestion Rents received from the Market from 2017 to 2021?

Response:
a) MRP is expected to result in both more efficient commitment of thermal units (ERUC) as well as the introduction of Locational Marginal Prices (LMPs). To the extent that MRP will address this overcommitment, the need to export energy from over-commitment resources will decline. LMPs will – all else being equal – ensure that investment occurs in parts of the grid where it is most needed. In doing so, it should reduce curtailment or unnecessary exports.
b) We were not retained to provide a forecast of Congestion Rents.
c) We were not retained to provide a forecast of Congestion Rents.
d) It is Power Advisory’s understanding that the shortfall is addressed by borrowing by the IESO and paid back through future congestion rent and TR Auction revenues.
e) Power Advisory does not have this data readily available. In other jurisdictions, this information would be publicly available; however, market data and information is severely restricted in Ontario by the IESO. Power Advisory recommends requesting the IESO to compile the requested information

f) See e)

PA-Staff-15

Ref.: Power Advisory Report / p. 25 / paragraph 66
Power Advisory Report / p. 31 / paragraph 77
Power Advisory Report / p. 35 / paragraph 86

Preamble

Power Advisory states on page 31: "it is difficult to see a clear trend on when energy exports are most likely to flow, as they occur even in hours where the spread in real-time prices between the two markets is extremely negative —meaning HOEP was significantly higher than real-time prices in New York".

Power Advisory states on page 25: "Overall, Ontario prices are significantly discounted compared to neighbouring wholesale markets — providing an ideal economic landscape for arbitraging Ontario supply into higher-priced wholesale markets and reducing system costs."

Power Advisory states on page 25: "the Market Clearing Price (MCP) and its hourly average, HOEP — in Ontario is often well below that of neighbouring jurisdictions".

Power Advisory states on page 35: "IESO does not publish offer and bid data —i.e. the price/quantity pairs that market participants submit into the wholesale market to generate or consume power. Every other wholesale market in North America publishes this data in an effort to provide price transparency and support a competitive market".

Power Advisory states on page 35: "...there is a lack of data regarding curtailment and surplus energy. The IESO does not provide hourly data for these amounts. Ontario's rate-regulated and contracted hydroelectric generators also do not provide surplus volumes on an hourly basis."

Power Advisory states on page 35: "export traders are highly responsive to prices".

Question(s)

a) Please clarify why Power Advisory states that export traders are highly responsive to prices given its other statements on the difficulty of seeing clear trends on when exports are likely to flow and on the significant discount of Ontario prices compared to neighbouring jurisdictions.

b) Please clarify and explain whether wholesale electricity prices will increase as a result of an increase to the ETS rate given the IESO's analysis, which expects that any increase in revenue from a higher ETS will be fully offset by a decrease in revenue from congestion rents.

Response:

a) Energy traders would not engage in activities that repeatedly result in an economic loss. As is clear in the data, energy flows – particularly on certain interties – will change hour-by-hour based on the prevailing market price. Nonetheless, Power Advisory’s analysis relied on HOEP (i.e. real-time) pricing data, as the IESO does not provide historical PD-1 pricing for the interties. Exports are scheduled based on PD-1 prices, not HOEP. As a result of changes in PD-1 and HOEP prices, there may be many hours where a trade appears uneconomic based on HOEP, but was economic in PD-1. Power Advisory had no way to address this in its modelling given the lack of data. In short, Power Advisory had to reach conclusions with the best available information. While we requested information on energy offers for exporters from the IESO, that information was not provided (although it is readily available in other jurisdictions). Additionally, it’s not clear what the “sink” is for each trade. A simplistic view of comparing the Ontario price to, for example, Zone A in NYISO may not account for the actual sink of the individual trade (i.e. it may be moving energy through Zone A into another zone).

b) It depends. All else being equal, an increase in the ETS charge would be expected to reduce HOEP, as it would decrease export demand, but would also result in a corresponding increase in GA. That said, if an intertie is congested, an increase in the ETS charge may reduce congestion rents first before having an impact on HOEP.

PA-Staff-16

Ref.: Power Advisory Report / pp. 31-33 / paragraphs 77-80
Power Advisory Report / p. 32 / Figure 10
Power Advisory Report / pp. 35-37/ paragraphs 88-90
Power Advisory Report / pp. 36-37 / Figures 13 and 14

Preamble

The text on pages 31-33 and Figure 10 shows a scatter plot of electricity exports from Ontario to NYISO and real-time price spreads between the two markets. The scatter plot appears to show no correlation between the price spread and Ontario exports. The discussion highlights potential explanations for this:

- Many export trades may result from long-term contracts as opposed to arbitrage transactions.
- The final destination of the exports is not known. They may be wheel-throughs destined for a third market.
- Surplus baseload generation in Ontario compels exports regardless of the price spread.

The discussion on pages 35-37 and Figures 13 and 14 seem to convey a different message. The figures show exports plotted against HOEP and reveal a negative correlation. The discussion concludes that exports are highly responsive to the Ontario price.

Question(s)

a) Is the price spread in Figure 10 (Real-time NY price minus HOEP) known to traders at the time their exports are scheduled?

b) If the answer to the above is no, would pre-dispatch prices in Ontario and hour-ahead prices in New York be better measures of any arbitrage opportunity available to Ontario exporters? What in Power Advisory's opinion would be the best measure of the price spread to which arbitrage traders respond to?

c) Should ICPs be added to the Ontario price to get a better measure of arbitrage opportunities? Why or why not?

d) Does the export data in Figure 10 reflect net exports from Ontario to NYISO (Ontario exports to NYISO minus NYISO exports to Ontario) or do they reflect gross Ontario exports to NYISO?

e) In Power Advisory's opinion, would gross or net exports be the better measure of arbitrage activity? Why?

f) In Figures 13 and 14 a negative correlation between Ontario exports and the HOEP is revealed. Do the Ontario exports reflect the total of all Ontario exports at all interties per hour?

g) Do the export data reflect gross exports or net exports?

h) In Power Advisory's opinion would the negative correlation between Ontario exports and Ontario prices reflect the behaviour of arbitrage traders as opposed to bilateral contract or wheel-through traders?

i) Is there any reason to expect a different mix of arbitrage, contract, and wheel-through traders at different interties?

j) Are there any factors Power Advisory can point to that would explain the apparent difference in responsiveness of exports to price measures as between Figure 10 and Figures 13 and 14?

k) In Power Advisory's opinion are the two sections of the report highlighted in this set of interrogatories conveying contradictory messages? Why or why not?

Response:

a) Power Advisory is not able to speculate on what is known (or not known) to all exporters at time of trades.

b) The spread between the ICP and the Ontario zonal price in New York would be a good arbitrage standard. That said, export traders may undertake a trade for a variety of reasons and target a variety of zones (i.e. have a "sink" outside of Zone A or Zone D in New York). The easiest way to determine the arbitrage value of a particular trade is to analyze its bid, which the IESO does not currently release.

c) To an extent, yes, as that is the value that export traders are willing to pay for exporting energy from Ontario into another jurisdiction.

d) They are gross exports.

e) Gross exports, as an import represents a different economic trade.

f) Correction. Figure 13 represents all exports, while Figure 14 is just on the New York interties.

g) Gross exports.

h) Without more detailed market data and information from individual exporters, Power Advisory cannot offer an opinion.

i) Yes, market dynamics, trading objectives and market presence in other jurisdictions would all influence different mix

j) No. As noted, trades can be undertaken in the short-term for reasons that are not readily apparent. Additionally, as noted in a previous response, Power Advisory's analysis relied on HOEP, while exports are scheduled based on PD-1 prices (and are exposed to market-based risks of HOEP in real time).

k) No. The two sections of the report highlight the severe lack of market data available and the inability to provide complete analysis to the Board under this proceeding. In Power Advisory's opinion, Ontario is a significant laggard as it relates to the release of wholesale electricity market data.

PA-Staff-17

Ref.: Power Advisory Report / p. 35 / paragraph 84

Preamble

Power Advisory states on page 35:

> The higher ETS rate imposes a significantly higher regulatory cost for exporting energy from Ontario — a cost that will have far-reaching impacts on various areas of the province's electricity sector, including the TR market, Environmental Attributes, system operations and future investment decisions at a time when the province is expected to need significant new, non-emitting capacity.

Question(s)

a) Please explain what is driving the expected need for significant new, non-emitting capacity.

b) What effect might the drivers described in response to part a) have on exports?

Response:

a) Federal climate change plan that is targeting zero emitting supply mix by 2035, vast and growing ESG objectives for industrial and large commercial customers, municipal sustainability objectives, and low-volume customers trying to manage volatile commodity costs (e.g., natural gas) along with supporting climate change objectives.

b) Depending on supply resource development over next decade, Ontario could end up with a supply mix that is variable and may at times have excess generation that must be exported to neighbouring jurisdictions or be curtailed.

PA-Staff-18

Ref.: Power Advisory Report / p. 39 / paragraph 94

Preamble

The Report states that congestion rents will also be impacted by the increase in the ETS rate. The Report then provides the change in congestion revenue.

Question(s)

a) Please confirm that congestion rents and congestion revenue are used interchangeably in the Report.

b) Please clarify that congestion rents refers to congestion rents received from the market and does not include TR Auctions Revenue. If this is the case please update references in the Report to congestion rents, accordingly, separating TR Payments to TR Holders from TR Auctions Revenue.

Response:

a) Confirmed.

b) Agreed, but we are not sure what the value of doing so is, as congestion rents and revenues discussed throughout the report relate solely to congestion pricing at the interties. As noted in other responses, Power Advisory looked only at congestion rents, as a perfectly efficient TR market, auction revenues and congestion rents would offset one another.

PA-Staff-19

Ref.: Power Advisory Report / p. 13 / paragraph 33
Power Advisory Report / p. 41 / paragraph 103
Power Advisory Report / p. 47 / paragraph 121
Power Advisory Report / p. 35 / paragraph 85

Preamble

Power Advisory states on page 13: "The greater (less) the revenue received from exporters through the ETS rate, the less (greater) the revenue requirement related to the Network rate pool that will be allocated to ratepayers as part of the UTR."

Power Advisory states on page 41: "When the ETS rate is increased by $4.69/MWh, it results in a simultaneous impact of reducing export demand — by shrinking the potential for arbitrage — and resulting in greater spilled supply."

Power Advisory states on page 47: "Finally, we strongly support the current design of intertie pricing that introduces a dynamic pricing mechanism that provides a clear price signal for the value of Ontario's energy supply."

Power Advisory states on page 35: "[...] there are a number of limitations with available public data compared to what is required to provide a highly accurate estimate price elasticity and system-wide benefits of exports".

Question(s)

a) How would demand from Ontario customers be affected by a change to the ETS and resulting change to the UTRs? For example, would an increase to the ETS result in an increase or decrease to Ontario customer demand? Would a decrease to the ETS result in an increase or decrease to Ontario customer demand?

b) What are the impacts to Ontario ratepayers of any Ontario demand changes resulting from changes in the ETS rate? For example, would Ontario ratepayers pay more or less if the ETS was increased or decreased?

Response:

a) If the decrease in export demand was so severe that it materially reduced HOEP, then it could result in an increase in Ontario demand. Power Advisory finds that scenario unlikely.

b) Any increase (decrease) in export demand would result in an increase (decrease) in HOEP, as export demand is added to the demand curve. In real-time, export bids are moved to $2,000/MWh to ensure they flow based on their PD-1 schedule. That said, most exports occur when HOEP is below $20, which includes the marginal cost of hydroelectric, nuclear, wind and solar generators. In Power Advisory's view, it's unlikely that exports will repeatedly push price beyond that threshold. As noted elsewhere, given the fixed-cost nature of Ontario's electricity system, a decrease (increase) in HOEP results in a nearly identical increase (decrease) in GA payments. GA costs will differ by class, given the cost allocation design of the Industrial Conservation Initiative (ICI).

PA-Staff-20

Ref.: Power Advisory Report / pp. 41 to 42 / paragraph 103

Preamble

The Report calculates the cost of increase in spill at OPG's regulated Hydro assets when the ETS rate is increased by $4.69/MWh. Power Advisory's analysis assumes that the decrease in exports when HOEP increases from $15.00/MWh to $20.00/MWh — is a proxy for an increase in the ETS rate of $5.00/MWh —which results in a 4.1 TWh reduction in hydro exports over the 2018 - 2021 time frame and an increase in spilled energy. Power Advisory applies a cost to Ontario ratepayers of $14.40 MWh for every unit of energy that is spilled.

Question(s)

a) Please explain why Power Advisory applied a HOEP increase range of $5.00/MWh instead of $4.69/MWh to determine the volume reduction in hydro exports.

b) Please provide the volume reduction in hydro exports with a $4.69/MWh increase in the ETS rate and update the cost of spill in 4a. of the Report. For this response, use HOEP from $15.00/MWh to $19.69/MWh.

c) Please explain why Power Advisory used a HOEP starting range of $14.40/MWh instead of $15.00/MWh.

d) Please provide the volume reduction in hydro exports with a $4.69/MWh increase in the ETS rate and update the cost of spill in 4a. of the Report. For this response, use HOEP from $14.40/MWh to $19.09/MWh.

Response:

a) For simplicity purposes – and lacking actual offer data from hydroelectric facilities – Power Advisory analyzed exports when prices were between $13-$14/MWh to $17-$19/MWh. The decline in exports in those ranges was used as a proxy for potential hydro curtailment, as exports that were previously profitable would no longer flow with the high ETS charge.

b) This request requires Power Advisory to conduct significant new analysis and would not significantly clarify any aspects of the initial report. Power Advisory is not able to provide the requested information with reasonable effort. To provide this information, Power Advisory would have to revise its models. Given the volume of interrogatories and short-time frame, it is not possible to adequately respond to this request. In any case, the result would be directionally similar.

c) This is based on the assumed highest marginal cost of hydroelectric facilities.

d) This request requires Power Advisory to conduct significant new analysis and would not significantly clarify any aspects of the initial report. Power Advisory is not able to provide the requested information with reasonable effort. To provide this information, Power Advisory would have to revise its models.

PA-Staff-21

Ref.: Power Advisory Report / p. 42 / paragraph 104
Power Advisory Report / pp. 45 to 46 / Table 4

Preamble
In Paragraph 104, Power Advisory estimates that with an increase in ETS rate by $4.69/MWh the reduction of exports will result in a reduction of market revenues from exports of $40.8 million.
In Table 4, which estimates the financial impact of decreasing the ETS rate to $0/MWh, there is no increase of exports shown.

Question(s)

a) Please provide the estimated increase in market revenues from exports for an ETS rate of $0/MWh.

b) Please explain why this is or is not a benefit to Ontario ratepayers.

Response:

a) The increase would be immaterial, as it would result in flowing of exports in the price range of $0/MWh to $1.85/MWh. Power Advisory's analysis assumes that a $1.85/MWh reduction in the ETS charge results in around 10,000,000 MWh of increased exports. Given the market revenues in the price range are low, the increase in market revenues would also be low. Most of the change in exports occurs in the low-price range where exports are most sensitive to price changes.

b) It's a benefit to Ontario customers, but a marginal one.

PA-Staff-22

Ref.: Power Advisory Report / p. 43 / paragraph 107
Preamble
Power Advisory states on page 43: "As exports decline, the combination of lower market prices (due to lower export demand and higher surplus or sub-marginal cost supply) [...]".
Question(s)
a) Please explain whether and how export demand increases the market prices in Ontario. For example, does the Ontario Market Clearing Price increase as a result of exports?
b) If market prices in Ontario do increase with higher export demand, please clarify how this increase in market prices in Ontario was factored into Power Advisory's analysis of impacts to Ontario ratepayers of changes in the ETS (for example, were the higher prices portrayed as a benefit or cost to Ontario ratepayers?)

Response:
a) All else being equal, an increase in export demand will result in higher market prices as it will shift the demand curve to the right and move up the supply stack to higher marginal cost resources. As noted elsewhere, exports are price sensitive and, as such, will respond to a materially higher HOEP that results from increased export demand. As noted elsewhere, given the fixed-cost nature of Ontario’s electricity system, a decrease (increase) in HOEP results in a nearly identical increase (decrease) in GA payments.
b) Higher market prices were considered a benefit for Ontario customers at it increased the amount of external revenues used to offset fixed system costs.

PA-Staff-23

Ref.: Power Advisory Report / p. 47 / paragraph 119

Preamble

Power Advisory states on page 47: "The future of Ontario's electricity market may be very different than the last ten years, when the province experienced significant amounts of SBG and curtailment".

Power Advisory states on page 47: "The IESO's current forecast expects SBG to decline materially with the closure of Pickering in 2026".

Question(s)

a) In light of the IESO's outlook for SBG, please clarify whether Power Advisory also expects that SBG will be lower in the future, particularly as units at the Pickering nuclear generating station begin to shut down?

b) How does Power Advisory expect the closure of Pickering will affect SBG?

c) Please comment on how the IESO's current forecast for SBG compares to the SBG experienced over the past decade.

d) What impact would materially lower SBG have on congestion rent payments and transmission rights revenue?

e) Please comment on the potential role of storage and other technologies for helping to manage SBG in Ontario over the next decade.

Response:

a) Power Advisory was not retained to provide a forecast for SBG. We do note that the most recent Annual Planning Outlook (APO) from the IESO forecasts a decline in SBG. See: https://www.ieso.ca/en/Sector-Participants/Planning-and-Forecasting/Annual-Planning-Outlook#:~:text=2021%20Annual%20Planning%20Outlook%20Report

b) See previous answer.

c) The current forecast for SBG is lower than what Ontario has experienced over the last decade. Ontario has experienced significant SBG over the past decade. That said, the future is inherently uncertain and, as noted in other answers, SBG may be more prevalent than is currently forecast, particularly in certain hours.

d) Lower SBG would likely result in lower congestion rents. That said, as noted in a response to SEC 11, congestion rent can occur even in hours when HOEP is high and Ontario is not experiencing SBG. Congestion rents and exports are partly a result of conditions in neighbouring markets, not just SBG in Ontario.

e) Power Advisory was not retained to analyze the future role of storage in Ontario.

PA-Staff-24

Ref.: Power Advisory Report / p. 10 / Table 1
Power Advisory Report / p. 22 / paragraph 60

Preamble

Table 1 states (along with footnote 2) that increases in wind and waterpower curtailment increase costs for Ontario ratepayers.

Power Advisory states on page 22:

> "Both contracted and regulated assets are typically made financially whole for supply sold in the wholesale market. For example, output from a wind contract may be contracted with the IESO at $135/MWh — meaning it will be paid that amount for any MW it sells into the wholesale market. If HOEP is $10/MWh, it will receive a $125/MWh payment, which is recovered from ratepayers through the Global Adjustment. Regulated hydroelectric rates are approximately $43.88/MWh, with a top-up payment made to cover the difference between revenue earned in the wholesale market and the regulated rate."

Question(s)

a) Please explain why wind and water curtailments increase costs for Ontario ratepayers.

b) Please reconcile Power Advisory's statement that wind and waterpower curtailment increase costs for Ontario ratepayers with its statement that contracted and regulated assets are typically made financially whole for supply sold in the wholesale market.

c) Does the total cost to Ontario ratepayers change depending on the fraction of generator revenues paid through the wholesale market versus the Global Adjustment? If so, how and why? Otherwise, please clarify.

Response:

a) Ontario customers must pay for curtailed energy. If a wind facility is curtailed, it provides no energy to Ontario customers, receives no external revenues as part of an export transaction, yet it receives its fully contracted/rate-regulated payment amounts.

b) Power Advisory doesn't believe a reconciliation is required. Contracted and rate-regulated assets are made financially whole when curtailed. They are also made financially whole when market revenues are insufficient to fully recover contracted or rate-regulated payment amounts.

c) The wholesale market is intended to allocate marginal costs to customers. The GA funding mechanism is, essentially, a capacity payment to make generators financially whole. As wholesale market revenues increase, the capacity payment made through the GA decreases. The total cost to customers of the entire system is largely the same, but is allocated differently depending on the wholesale market/capacity revenue streams.

PA-Staff-25

Ref.: Power Advisory Report / p. 34 / paragraph 83
Power Advisory Report / p. 42 / Table 3

Preamble
Power Advisory states on page 34: "Power Advisory's analysis using historical data concludes that between 2018 and 2021 the impact of increasing the ETS by $4.69/MWh would be to reduce average hourly exports by 160 MW and congestion rents by $169 million — although that decrease would be offset by greater total export revenues due to the near $5/MWh increase in the ETS rate."
Page 43 Table 3 is titled "Financial Impact of Higher ETS Rate". Question(s)

a) With respect to Table 3, please explain whether or not it is double counting to add "Reduced Market Revenues from Lower Exports" and spills/curtailments ("Financial Impact of Increased Hydro Spill" and "Ontario Ratepayer Impact from Curtailed Wind Supply"). If not, please explain why not. If yes, please revise the table and conclusion.
b) The table refers to a "Financial Impact" and an "Ontario Ratepayer Impact" related to hydro spill and wind curtailment, respectively. Please clarify the difference between the terms use if a difference was intended.

Response:

a) It is not double counting, as Power Advisory only counted reduced market revenues when HOEP is greater than $18/MWh
b) They can be used interchangeably.

PA-Staff-26

Ref.: Power Advisory Report / p. 10 / Table 1

Preamble

Page 10 Table 1 estimates that wind curtailment costs would have increased over the 2018 through 2021 period because of an increase to the ETS.

Question(s)

a) What was the approximate total wind production and cost prior to curtailment over the 2018-2021 timeframe (assuming the current ETS of $1.85/MWh)?

b) How much additional wind production does the Power Advisory analysis estimate was curtailed over the 2018-2021 timeframe because of the increase in ETS to $6.54/MWh?

c) Approximately what proportion of the values in (a) does the estimated additional curtailed production and estimated additional curtailment cost of $17,985,020 represent?

Response:

a) Total (tx-connected) wind output over 2018-2021 was 45.6 TWh, according to publicly released IESO data. The Global Adjustment amounts related to wind supply total $7.3 billion, but included taxpayer financed subsidies throughout 2021 and are not inclusive of wholesale market revenues.

b) Power Advisory assumes the decline in exports from raising the ETS – which would amount to 7.6 TWh – would be curtailed wind supply. In the absence of detailed curtailment data from the IESO, Power Advisory believes this is a reasonable assumption. See the attached methodology for the calculation.

c) The $17 million figure is 50% of the curtailed amount.

PA-Staff-27

Ref.: Power Advisory Report / p. 10 / Table 1

Preamble

Page 10 Table 1 estimates that waterpower curtailment costs would have increased over the 2018 through 2021 period because of an increase to the ETS.

Question(s)

a) What was the approximate total waterpower production and cost prior to curtailment over the 2018-2021 timeframe (assuming the current ETS of $1.85/MWh)?

b) How much additional waterpower production does Power Advisory's analysis estimate was curtailed over the 2018-2021 timeframe because of the increase in ETS to $6.54/MWh?

c) Approximately what proportion of the values in (a) does the estimated additional curtailed production and estimated additional curtailment cost of $59,811,638 represent?

Response:

a) Power Advisory did not calculate hydropower supply, as it wasn’t required for this analysis.

b) See previous answer.

c) See previous answer.

PA-Staff-28

Ref.: Power Advisory Report / p. 9 / paragraph 18
Power Advisory Report / p. 24 / paragraph 63
Power Advisory Report / p. 10 / Table 1

Preamble
Power Advisory states on page 9: "A higher transaction cost will, in general, reduce exports in hours when it is economically advantageous to sell Ontario supply into neighbouring markets"
Power Advisory states on page 24: "External revenues help reduce costs for domestic ratepayers".
Power Advisory states on page 24: "[...] more surplus and sub-marginal cost supply that is sold into neighbouring markets, the lower the overall system cost will be for Ontario ratepayers."
Page 10, Table 1 estimates the change in export revenues over the 2018 through 2021 period resulting from a change to the ETS.

Question(s)

a) Please confirm whether the term "Market Revenues" in Table 1 refers to revenues earned by exporters for electricity exports (i.e., for the sale of electricity out of Ontario). Otherwise, please clarify.
b) Please confirm whether the term "Export Revenue" in Table 1 refers to ETS payments by exporters. Otherwise, please clarify.
c) Is Power Advisory saying that revenues earned by exporters for the sale of electricity out of Ontario (Market Revenues in Table 1) reduce the total cost paid by electricity ratepayers in Ontario? If yes, please explain how. Otherwise, please clarify.
d) What would have been the total dollar amount of "Market Revenues" (assuming the term refers to revenues earned by exporters for electricity exports) over the 2018-2021 timeframe assuming the current ETS of $1.85/MWh?
e) Approximately what proportion of the value in d) does the estimated decrease in Market Revenues of $40,871,596 in Table 1 represent?
f) How would Power Advisory characterize its confidence in the $40,871,596 figure? What are the key uncertainties to this result?
g) How much of the decrease in export revenues in the "Increasing ETS Rate to $4.69/MWh" scenario in Table 1 was revenue that would have covered the marginal cost of serving the demand that would not have existed but for the export demand? How much of the remaining export revenue would have therefore been available to reduce the total cost paid by electricity ratepayers in Ontario?
h) In Power Advisory's estimate, what share and dollar value of export revenues between 2018 and 2021 was useful in reducing the total cost paid by electricity ratepayers in Ontario as opposed to paying for the marginal cost of supplying the export quantity? Is the larger or smaller of these two shares reflected in Table 1 as the impact of reduced export volumes on Market Revenues? If it is the larger, please explain why this is not an overstatement of the impact of export revenues (Market Revenues) towards reducing the total cost paid by electricity ratepayers in Ontario.

Response:

a) Confirmed. Market revenues is the revenue exporters provide to Ontario when purchasing energy to export beyond $18/MWh.

b) Confirmed.

c) Exporters provide additional revenue by purchasing energy in Ontario. As noted throughout the evidence, that revenue is used to offset fixed costs within Ontario. If exporters did not purchase energy, curtailment would increase, HOEP would be lower and system-wide costs allocated to Ontario customers would be higher. The interplay between a higher ETS – which increases revenue for Ontario customers – and system-wide impacts (higher curtailment, for example) is what our analysis is trying to highlight.

d) Market revenues for exporters would have been exports multiplied by HOEP.

e) A small portion. Exports over 2018-2021 were more than 75,000,000 MWh. Even if the average HOEP-weighted price for exports was $5/MWh, that would be more than $375,000,000 in revenue.

f) Confident with caveats (i.e., input information limitations, uncertainty of future supply mix). There is a lack of data in Ontario compared to other jurisdictions, including (but not limited to): lack of hourly curtailment by fuel type and bid and offers from market participants.

g) Power Advisory does not understand the question.

h) Power Advisory does not understand the question.

PA-Staff-29

Ref.: Power Advisory Report / p. 24 / paragraph 64
Power Advisory Report / p. 24 / Figure 5
Power Advisory Report / p. 25 / paragraph 65
Power Advisory Report / p. 25 / Figure 6

Preamble

Power Advisory states on page 24 (with reference to Figure 5): "Ontario's baseload supply accounts for as much as 70% of installed capacity [...]".

Power Advisory states on page 25 (with reference to Figure 6): "When looking at actual energy output — not just installed capacity — the prevalence of Ontario's baseload supply is more extreme. In Ontario, baseload supply — including nuclear, hydro and solar — provided around 92% of all supply between 2018 and 2021."

Question(s)

a) Please provide the numbers for Ontario in Figures 5 and 6 by fuel type in a way that also shows the type and quantity of Ontario supply that is not baseload.

b) Please clarify what criteria Power Advisory used to determine what was and was not baseload supply for purposes of creating Figures 5 and 6.

Response:

a) Power Advisory cannot adequately respond to this question due to the lack of bid and offer data. It's not possible to tell what amount of hydro is must-run, baseload supply, compared to what amount is fully dispatchable and responsive to energy prices. A detailed review of offers by hydro facilities would allow for such an analysis. Additionally, it's not clear what amount of gas supply is committed at its Minimum Loading Point (MLP) and is also not dispatchable.

b) Power Advisory considered all nuclear, hydro, wind and solar as baseload supply. We recognize that some amount of hydro supply is dispatchable, certain nuclear units can be maneuvered (i.e. their output is essentially re-routed) and renewable units can be dispatched down (i.e. curtailed).

PA-Staff-30

Ref.: Power Advisory Report / pp. 27-28 / paragraph 70
Power Advisory Report / p. 28 / Figure 8

Preamble

Power Advisory states on pages 27-28: "With HOEP set at $15/MWh and a lack of congestion on the intertie [...] all of the export bids are economic. [...] The highest-priced bid is the last bid to be considered uneconomic".

Question(s)

a) The words in the text box on Figure 8 refer to export bids. The X axis refers to export offers. Please clarify whether this a typographic oversight or an intentional distinction. If it is an intentional distinction, please explain.

b) Please clarify what is meant by the excerpt from pages 27 and 28 above in which the first sentence refers to economic bids and the second refers to an uneconomic bid.

Response:

a) This is a typographic oversight. It should be export bid.

b) The highest bid from an exporter will always be the last bid to be considered uneconomic – i.e. that exporter is willing paying the highest amount to export energy from Ontario.

RESPONSE TO INTERROGATORIES FROM ENERGY PROBE

PA-EP-1

Reference: Power Advisory Report, pages 3 and 6
Preamble: "What is likely to happen to ICP revenues and other ratepayer benefits if the ETS rate is increased to $6.07/MWh?"

a) Please explain the origins of the $6.07/MWh ETS rate on page 3 and $6.54/MWh ETS rate on page 6.

b) Please reconcile the differences between the two numbers.

Response:

a) See: EB-2021-0110, Exhibit H, Tab 9, Schedule 1, Page 5 of 6. The figures come from the Elenchus evidence filed as part of this proceeding.

b) The $6.54/MWh figure is an adjusted ETS. Elenchus describes the adjustment: "Rates are adjusted by 7.77%, calculated as the sum of HONI's 2023 Network Revenue Requirement and the Network Revenue Requirements of all other transmitters (as per EB-2020-0251) divided by HONI's 2023 Network Revenue Requirement." Power Advisory takes no view on whether the adjustment done by Elenchus is accurate or correct.

PA-EP-2

Reference: Power Advisory Report, page 12
Preamble: "The methodology proposed in this proceeding relies on a traditional cost allocation methodology to justify a near four-fold increase in the ETS rate. The methodology does not incorporate cost causality principles in its conclusion – neither the planning of the transmission grid or generation investments consider export demand as part of the investment planning process."

a) What are "cost causality principles" as understood by Power Advisory?

b) Is Power Advisory claiming that "traditional cost allocation methodology" does not incorporate cost causality principles?

c) Does Hydro One make generation investments?

d) Why does Power Advisory believe that Hydro One does not consider export demand in its investment planning?

e) In the opinion of Power Advisory should cost allocation methodology be used to develop the ETS rate? If the answer is yes, please explain how it should be used. If the answer is no, please explain why not?

Response:

a) At a high level, cost causation means that someone who causes a cost to be incurred is required to pay for it – essentially that any party that imposes a system-wide cost is allocated that cost. Obviously, regulators can choose to interpret this principle broadly and can include other principles, such as simplicity and transparency, when determining what costs should be allocated and to who.

b) Power Advisory is stating the opposite – that the proposed methodology moves away from cost causation as it allocates a portion of costs to customers that are not causing them.

c) Power Advisory does not understand the relevance of the question. Hydro One's Remote division does make generation investments, but we question the relevance to this proceeding.

d) In both this proceeding and previous proceedings Power Advisory is not aware of Hydro One disputing this fact. The IESO has explicitly stated in this proceeding that it does not plan the system to account for exports. From the IESO's evidence filed in this proceeding: "***However, the needs and activities of competitive exporters (e.g., volume and direction of transactions) are not considered when planning the transmission system, and so are not a primary driver of investment." (emphasis added)***

e) If export customers impose a cost on Hydro One – either to maintain the interties or some other asset – than the cost that they are imposing should be allocated to them via an ETS charge if it is not otherwise offset or collected via congestion rents and TR revenues.

PA-EP-3

Reference: Power Advisory Report, page 10, para 22
Preamble: "All of the evidence in this proceeding is clear that export customers do not impose a cost on Ontario's electricity grid."

a) Please explain list all types of costs that can be imposed on an electricity grid and explain why export customers do not impose any of these costs.

b) Please confirm that export customers are users of Ontario's electricity grid.

c) Is Power Advisory opposed to the user pay principle where users of an asset pay for their proportionate use of that asset?

Response:

a) Power Advisory does not understand the relevance of this question. A myriad of costs can be imposed on the system. Apart from direct interties, Hydro One's investment planning – according to our review of the evidence – does not incorporate export customers, nor does it explicitly account for customers in its investment plans. Export customers also receive a different level of service – i.e. they can be curtailed at their own expense.

b) Confirmed.

c) No. But applying the user pay principle must include a). distinct services between customers (interruptible versus firm, for example), b). all revenues collected from a particular customer class (congestion rents and TR revenues) and c). the system-wide benefit that a particular customer class provides to the system (moving fixed cost, surplus supply to a different market for a higher price).

PA-EP-4

Ref: Power Advisory Report, page 10, and Table 1
Preamble: "The financial impact to Ontario ratepayers from increasing the ETS rate to $6.54/MWh would have been a net increase in costs of $42.6 million over the 2018 – 2021 timeframe. The increase is a result of lower congestion rents, increased curtailment at wind and hydro generators and lower market revenues from selling Ontario power in neighbouring jurisdictions."
Questions:

a) Please explain why the quote refers to increasing the ETS rate to $6.54 / MWh while Table 1 presents an increase to $4.69/ MWh, and both claim a benefit to ratepayers of $42.6 million.

b) Please confirm that Table 1 deals with two alternatives. One alternative is increasing the rate from $1.85/ MWh to $4.69/ MWh and the other alternative is decreasing the ETS rate from $1.85/MWh to zero. Why did Power Advisory not consider an alternative that would keep the ETS rate at $1.85/ MWh?

c) Please list all assumptions used in the calculation that support the quantities shown in Table 1.

d) For each of the two alternatives shown in Table 1, please explain how the following quantities were calculated:

   i) Wind Curtailment Cost
   ii) Congestion Rent
   iii) Hydro Curtailment Cost
   iv) Market Revenues

Response:

a) It is an increase of $4.69/MWh of the ETS charge to $6.54/MWh.

b) No. One alternative is to increase it to $6.54/MWh, while the other is to decrease it to $0/MWh. The IESO's evidence detailed the benefit of the current ETS rate of $1.85/MWh. We wanted to show what would happen to system-wide benefits for Ontario ratepayers from changing the ETS rate further.

c) They are detailed in the report.

d) (i) to (iv) - These are detailed in the report.

PA-EP-5

Ref: Power Advisory Report, page 16, paragraph 49
Preamble: "This "opportunity service" targets excess capacity in the system that is being inefficiently used by existing domestic demand."
Questions:

a) Does Power Advisory suggest that any system that has spare capacity is inefficiently used?

b) Is not spare capacity needed to rapidly respond to changes in demand and supply? Would nota system with no spare capacity have reliability issues?

c) Why should exporters have right to spare capacity?

Response:

a) The efficient use of a fixed cost system (or any economic system) is to maximize its utilization. The more throughput that can accommodated – and revenue generated as a result of that throughput – the lower will be the per unit cost. But this only occurs if the additional unit does not increase fixed or long-term costs. A transmission grid that is built to accommodate peak demand will have spare capacity in most hours (8759 to be exact) of the year. Introducing a limitation to export customers when the system has spare capacity is an inefficient use of the grid. Export customers are also interruptible, meaning they are curtailed when there is no longer spare capacity in the system. Export customers are not made financially whole for interruptions as a result of internal transmission limits.

b) Power Advisory agrees that spare capacity in the electricity sector is prudent planning. There is spare capacity on the grid in almost every hour of the year. In years when there is an unexpected decline in demand (a recession or pandemic), there is likely spare capacity in all hours of the year.

c) Exporters do not have a right to spare capacity, as they are interruptible customers. Exporters provide value by moving energy from Ontario to higher priced markets and, in many cases, avoiding curtailment to the greatest extent possible. To Power Advisory's knowledge, no export customer has advocated for increased internal transmission or intertie capacity.

PA-EP-6

Ref: Power Advisory Report, page 17, paragraph 49
Preamble: "Any cost allocation methodology should recognize the economic opportunity nature of exports and that exports do not purchase a fixed amount of capacity from the system."

a) Please explain how a cost allocation methodology would recognize an "economic opportunity" and use it in setting rates.

b) Is Power Advisory aware of a case where economic opportunity was used by a utility to set rates that were approved by a regulator? If the answer is yes, please provide a reference.

Response:

a) It should consider that export customers operate on an economic opportunity basis only and are not committing to long-term costs or obligations. When the price-spread opportunity between markets does not exist, an export customer will not utilize the transmission network, even if spare capacity exists.

b) Two examples exist in Alberta. There is an export opportunity service (XOS) and Demand Opportunity Service (DOS) under the Alberta Electricity System Operator's Transmission Tariff.

PA-EP-7

Ref: Power Advisory Report, page 20, paragraph 57
Preamble: "Zero marginal cost supply includes baseload supply from nuclear plants, must-run hydro supply and intermittent supply from wind generators and, to a lesser extent, solar generators. Simplistically, baseload supply is limited in its ability to respond to price – nuclear units for the most part cannot be easily shutdown and offer into the wholesale market at extremely negative prices, storage capability at hydro generators is limited and wind and solar generators generate under intermittent physical conditions and typically offer supply at $0/MWh or below".

a) What is Power Advisory's definition of baseload?

b) Why does Power Advisory consider wind and solar generators to be baseload?

Response:

a) Baseload resources are resources that are unresponsive to prices. They either run for physical reasons (i.e. some water must pass through the turbine for safety or environmental reasons) or run because it is highly uneconomic to not operate whenever fuel is available (e.g., a nuclear unit cannot turn on and off easily, wind and solar generators operate due to prevailing weather patterns).

b) These resources are unrelated to demand and operate solely as a result of prevailing weather conditions. The term baseload may be outdated given the changing investment patterns in electricity grids. A more appropriate term may be price and demand unresponsive, which would include must-run hydro and nuclear.

PA-EP-8

Ref: Power Advisory Report, page 25, paragraph 66
Preamble: "Overall, Ontario prices are significantly discounted compared to neighbouring wholesale markets – providing an ideal economic landscape for arbitraging Ontario supply into higher-priced wholesale markets and reducing system costs."

a) Is the reduction of Ontario supply costs the only purpose of arbitraging?

b) Do generators benefit from arbitraging?.

Response:

a) No. To arbitrage is to move a good from a lower-price to higher-price market. Ontario's unique hybrid market design results in arbitrage between Ontario and neighbouring markets providing a benefit to Ontario ratepayers, as it takes surplus supply that otherwise will be paid for by Ontario ratepayers and sells it to neighbouring jurisdictions.

b) Given the fixed nature of Ontario's electricity grid, most generators do not need to actively engage in arbitrage, but likely undertake some form of energy trading.

PA-EP-9

Ref: Reference: Power Advisory Report, page 29, paragraph 72
Preamble: "When the intertie is congested, congestion rents are collected – the higher price that exporters pay compared to HOEP ($20/MWh) for each MWh of exports – in an account to be distributed to ratepayers. In a perfectly efficient market, congestion rents either accrue to ratepayers or are used to fund transmission expansion – essentially, funding an economic buildout of intertie capacity."
Is Power Advisory suggesting that Hydro One should collect congestion rents in an account that Hydro One would use to pay for construction of transmission facilities that would relieve congestions at interties? If the answer is yes, please explain how Hydro One would do that. If the answer is no, please explain what Power Advisory is suggesting.
Response:
No. In a perfect market, congestion rents can be used to fund transmission expansion, but no party in Ontario – exporters or domestic customers – is proposing this outcome.

PA-EP-10

Ref.: Reference: Power Advisory Report, page 30, paragraph 74
Preamble: "A regulated process would typically only be used when there is a market failure. In this case, there is no market failure on the province's interties."

a) Please define "market failure".

b) Please list all instances of market failure in the 2018 to 2021 period.

c) Does Power Advisory expect that market failure is likely to occur in the next five years.

Response:

a) Market failure can mean a number of things. Typically, Power Advisory assumes a market failure occurs when there is abuse of market power or lack of competition.

b) Market Surveillance Panel (MSP) has described many situations where the Ontario wholesale electricity market has not been operated efficiently. See the State of the Market commentary by the MSP for a detailed discussion: https://www.oeb.ca/sites/default/files/msp-monitoring-report-20200716.pdf

c) Power Advisory has no view on future market failure.

PA-EP-11

Ref.: Reference: Power Advisory Report, page 35, paragraph 87
Preamble: "Surplus hydro supply is doubly bad for Ontario ratepayers, as they are charged the full regulated rate for it, while receiving no external market revenue to offset a portion of the regulated rate".
Are surplus wind and solar also bad for Ontario ratepayers? Please discuss their impact and compare it to the impact of surplus hydro.
Response:

Power Advisory's understanding is that regulated and most unregulated generators in Ontario are generally compensated for curtailment. Exporting energy that would otherwise be curtailed provides additional revenue to offset costs that are ultimately borne by Ontario ratepayers.

RESPONSE TO INTERROGATORIES FROM SEC

PA-SEC-1

Ref.: [p.9]
Please confirm that Power Advisory's quantitative analysis is based on 2018-2021 supply and demand conditions and market data. If confirmed, please confirm that insofar as those conditions change in the future, Power Advisory's analysis will be impacted.

Response:

Power Advisory confirms the first question. Power Advisory does not confirm the second question. The future is inherently uncertain, both in terms of the Ontario wholesale electricity market, but also the neighbouring jurisdictions. In general, exports will continue to provide an overall value to Ontario ratepayers by allocating energy in an economically efficient manner.

PA-SEC-2

Ref.: [p.16-17]
If exports provided no monetary benefits to domestic customers (discussed in paragraph 50-53), would Power Advisory still believe that the application of cost causation principles should result in no ETS rate for the reasons set out in paragraph 47 to 49? Please explain your response.

Response:

Power Advisory struggles to find a reason why exports would provide no monetary benefit for domestic customers given the fixed nature of Ontario's electricity grid. Exports are simply an economic transaction – moving energy (surplus or otherwise) from one market to a higher priced market. If that economic opportunity erodes, so too will exports. That said, given Ontario's supply mix and market design – both current and future – compared to neighbouring jurisdictions, we struggle to see a time when there are no monetary benefits realized from exports. As noted in SEC 11, exports can provide congestion rent even in higher-priced hours (i.e. hours where HOEP is greater than $40/MWh)

PA-SEC-3

Ref.: [p.21]
Power Advisory notes that with respect to hydroelectric generators, "selling supply at a "loss" reduces the economic efficiency of the wholesale market, but occurs often in Ontario as a combination of the hybrid design and surplus baseload supply". Please provide Power Advisory's opinion on how much of this is caused by incentives of OPG's Hydroelectric Incentive Mechanism (HIM) and the existence of a Surplus Baseload DVA, as opposed to operational features of hydroelectric generators.

Response:

Power Advisory was not retained to analyze the role of the Hydroelectric Incentive Mechanism (HIM) or deferral accounts as part of this proceeding.

PA-SEC-4

Ref.: [p.31, 35]
Please reconcile Power Advisory's view that "it is difficult to see a clear trend on when energy exports are most likely to flow, as they occur even in hours where the spread in real-time prices between the two markets is extremely negative – meaning HOEP was significantly higher than real-time prices in New York", with statements that "available public data of export volumes, intertie prices and HOEP, clearly show that export traders are highly responsive to prices."

Response:

In many hours the data can be "noisy" – i.e. exports will continue to flow even when HOEP is significantly greater than neighbouring markets. Partly this can explained by exports being scheduled in PD-1, but flowing in real-time. In can also be explained by the economic opportunity of export traders, which recognize a short-term loss as part of a physical bilateral or other agreement. It can also be explained by a lack of understanding around the final "sink" for any trade. A detailed review of export bids would provide a clearer understanding of price responsiveness.

Also, note that the two graphs are showing two different things. One is showing how exports flow based on price spreads between the two markets (using the zonal price in NYISO), while the other is showing how exports flow compared to HOEP.

In any case, the averages provided by Power Advisory by various price buckets clearly show that exports respond to price signals.

PA-SEC-5

Ref.: [p.34]
How much ICP revenue does Power Advisory estimate is avoided as a result of Transmission Rights?

Response:

Power Advisory did not estimate the amount of avoided congestion rents due to Transmission Rights. Nonetheless, assuming ALL congestion was avoided, an efficient market would fully recover that loss from the sale of TRs (market participants would pay no more for TRs than the cost of congestion).

PA-SEC -6

Ref.: [p.35]
Power Advisory states that “there are a number of limitations with available public data compared to what is required to provide a highly accurate estimate price elasticity and system-wide benefits of exports”:

a. Please confirm that the IESO has this data.

b. Did the Power Advisory, through its sponsor APPrO, request this data by way of interrogatories to the IESO? If not, please explain why it did not.

Response:

a. Confirmed.

b. Yes. The IESO expressed concerns around releasing what is, in their view, sensitive and confidential information in this process.

PA-SEC-7

Ref.: [p.36-38]
Please provide the underlying spreadsheets/models, and identify the source of the data for Figures 13, 14, and 15.

Response:

See attached methodology and spreadsheet.

PA-SEC-8

Ref.: [44, 49]
Power Advisory states that, “[b]ased on exports between 2018 and 2021, a $4.69/MWh increase in the cost to export energy from Ontario will reduce exports by more around 17.0 TWh – declining from 75.9 TWh to 58.9 TWh.” It also states that, “a decrease in the ETS rate from $1.85/MWh to $0/MWh results in an increase in export volumes of more than 10 TWh – increasing from around 75.9 TWh to 86 TWh.” Please provide a step-by-step explanation, including all supporting data, assumptions, and all specific calculations,, regarding how the 58.9 TWh and 86 TWh amounts were calculated.

Response:

See attached methodology and spreadsheet.

PA-SEC-9

Ref.: [p.44, 49]
Power Advisory calculated that an increase in the ETS rate will lead to a "reduction in congestion rent totals $169.0 million – falling to $397.9 million from $567.0 million, or a near 30% decline, in congestion rent collected". It also calculated that a decrease in the ETS rate to $0 will result in an "increase in congestion rent totals $111.0 million – increasing to $678.1 million from $567.0 million in congestion rent collected over the 2018 – 2021 time period." Please provide a step-by-step explanation, including all supporting data, assumptions, and all specific calculations, regarding how the $397.8M and $678.1 in congestion rents were calculated.

Response:

See attached methodology and spreadsheet.

PA-SEC-10

Ref.: [p.41, p.45, 49]
Power Advisory states that a "higher ETS will reduce exports in hours when the province is curtailing wind supply", and provides an estimate that a higher ETS will result in as much as 7.6 TWh of increased wind curtailment between 2018 and 2021." It also estimates that a ETS rate of $0 would have resulted in "as much as 5.8 TWh of potential curtailment could have been avoided." Please provide a step-by-step explanation, including all supporting data, assumptions, and all specific calculations, regarding how the 7.6 TWh and 5.8 TWh in congestion rents were calculated.

Response:

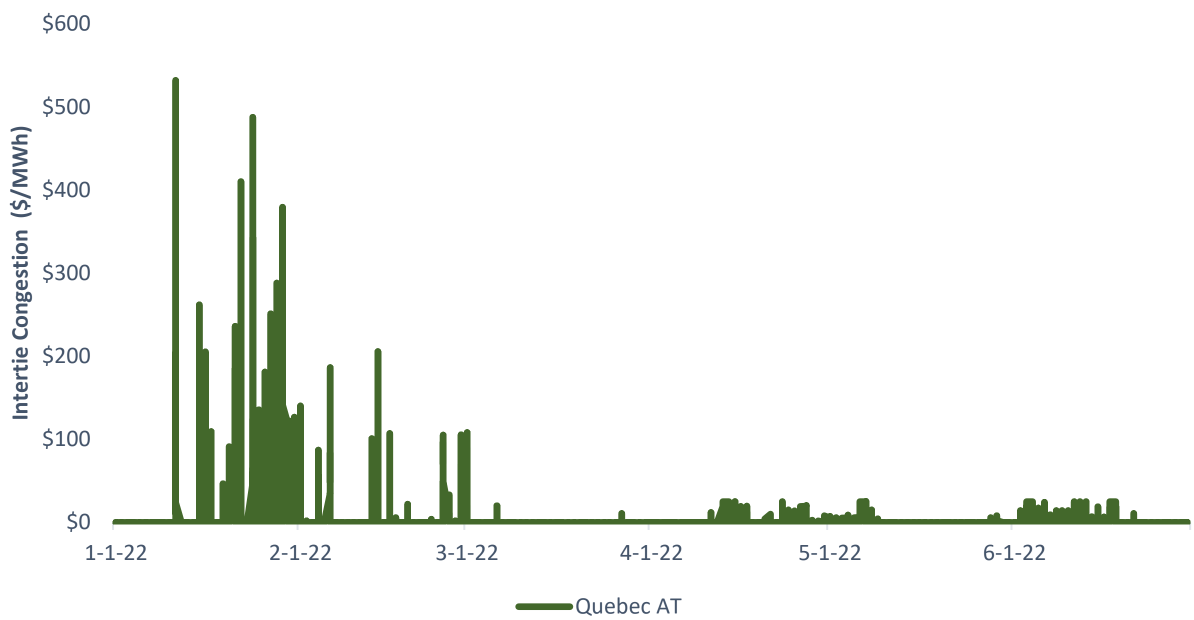
See attached methodology and spreadsheet.

PA-SEC-11
Ref.: [Table 42-43, 45-46]
Power Advisory's analysis is based on 2018 to 2021 data. Please revise the analysis, to show the impacts for each for 2018, 2019, 2020, 2021 and year-to-date 2022. Please detail all supporting calculations and assumptions.

Response:
Power Advisory will not complete the undertaking given the time frame and volume of interrogatories.

What we can say is that the Ontario grid compared to neighbouring jurisdictions has not materially changed in 2022 compared to 2021. What we show is that congestion rents have continued to be material at certain interties, particularly at the HVDC intertie with Quebec in early 2022. Many of the benefits of interties that were discussed in our report would be realized in these hours. Of particular importance is that this shows that intertie congestion can occur even in hours where there is no surplus supply (i.e. HOEP is greater than $0-$5/MWh). In many hours this winter Quebec was simultaneously importing energy from Ontario – and paying high congestion rents – while exporting at the same time to ISO-NE and other markets. Again, this highlights the complex nature of energy exports and determining the final "sink" is not always clear.

Figure 1Hourly Intertie Congestion at the QC HVDC Intertie



PA-SEC-12

Ref.: [p.47]
Assuming the IESO surplus baseload generation forecast is accurate, please discuss how it would impact Power Advisory's analysis.

Response:

A reduction in SBG conditions would, all else being equal, result in less $0/MWh or lower price hours. This would be expected to reduce the overall number of exports. That said, a number of neighbouring jurisdictions are expected to experience tightening capacity conditions in the coming years. As a result, the economic opportunity between Ontario and these markets – and the congestion rents that typically occur as a result – may continue to be material. Perhaps more importantly, the future is inherently uncertain. IESO's SBG forecast is just that, a forecast of a reasonable outcome. The forecast is not actual future data and can change significantly in short periods of time (e.g., COVID-19 demand drop). Even if the IESO's SBG forecast is accurate on a yearly basis, there can be short-term constraints or volatility in demand that can influence export opportunities.

RESPONSE TO INTERROGATORIES FROM VECC

PA-VECC-1.0

Reference:
Power Advisory Evidence, pages 4; 7-8 and 16-18

Preamble:
At page 4 the Evidence quotes the OEB's Decision on Expert Evidence and Procedural Order No. 2 as follows:
"APPrO has stated that Mr. Lusney and Mr. Yauch have considerable expertise in energy market analysis, regulatory affairs, generation development, system planning, market assessment and energy policy analysis. The OEB is prepared to accept both Mr. Lusney and Mr. Yauch as experts in energy market and energy policy analysis for this evidence, and will proceed on that basis. It is not clear whether Mr. Lusney or Mr. Yauch are experts in regulatory affairs, but the OEB concludes this is not required for this evidence. Previous appearances before a regulatory tribunal provide helpful experience in regulatory affairs, but do not necessarily qualify a person as an expert in the field."
At pages 7-8 the Evidence provides an overview regarding the areas of experience and expertise of the two authors.
At pages 16-18 the Evidence provides commentary and critique regarding the cost allocation methodology proposed by Elenchus.

Question(s)

1.1 It is noted that neither Mr. Lusney nor Mr.Yauch has been accepted by the OEB as an expert in the area of cost allocation (and more specifically cost allocation as it relates to transmission tariffs). Is the commentary and critique of Elenchus' proposed cost allocation methodology meant to represent an "expert opinion"?

1.2 If yes, is the OEB now being requested to accept Mr. Lusney and Mr. Yauch as experts in cost allocation and, if so, on what basis?

Response:

1.1 Yes.

1.2 Please see the cover letter accompanying these interrogatory responses.

PA-VECC-2.0

Reference:
Power Advisory Evidence, pages 5 and 34-46
Exhibit I, Tab 8, Schedule 7 a), IESO's 2021 APO
Preamble:
At page 5 the Evidence states:
"Given the highly complex nature of the electricity market – both in Ontario and other jurisdictions – the report is as simplified as is reasonably possible. Electricity trading is highly dynamic, involves many physical and financial considerations and occurs amidst the real-time balancing of an incredibly complex physical electricity grid. This report captures that complexity to the greatest extent possible and provides an analysis on how traders and other market participants would respond to a change in the ETS rate – which, if increased, would materially change the transactional cost of energy trading from Ontario into neighbouring markets. Where possible, we have focused on simplicity rather than attempt to capture the many nuances – both physical and financial – that are evident in Ontario's electricity sector. We have also undertaken a historical analysis to avoid complications around forecasting future conditions". (emphasis added)
Question(s)
2.1 Given the above comments, should readers of the Evidence interpret the results presented on pages 34-46 as an indication regarding the "directional impacts" of higher or lower ETS rates as opposed to specific estimates as to the impact of increasing or decreasing ETS rates by the amounts assumed in the Evidence over the historical period used in the analysis?

2.1.1 If not, why not?

2.2 Given that the analysis was performed using data from the historical period 2018-2021, to what extent does the applicability of the results to the period 2023-2027 (i.e., the period covered by Hydro One's current Joint Transmission and Distribution Rate Application) depend on electricity market conditions in Ontario for the period 2023-2027 being similar to those in 2018-2021?

2.2.1 If the applicability does not depend on the market conditions being similar please explain why.

2.2.2 If the applicability does depend on the market conditions being similar, what are the market conditions for which similarity is particularly important for the results to be applicable and why? Also, based on the IESO's 2021 APO, are these conditions expected to similar over the 2023-2027 period?

Response:
2.1 To an extent, yes. Given more detailed bid and offer data, as well as hourly curtailment amounts by asset, would allow for a more accurate assessment of the impact. What our analysis shows is that increasing the ETS rate – and increasing the fixed charge component of exports – will result in negative impacts in other areas of the total electricity system.

More importantly, the analysis shows that it's not a one-to-one outcome in terms of increasing the ETS. While increasing it may increase revenues from each export, it will also reduce overall export activity and result in higher costs in other parts of the system (i.e. greater curtailment in hours of surplus supply).

2.1.1 See previous answer.

2.2 Power Advisory believes that the results are indicative of the future.

2.2.1 Ontario's electricity grid is expected to change – we don't dispute that reality. How the change will unfold is still unclear. The IESO is running multiple procurement programs to, potentially, procure up to 8,000 MW of capacity. This would mark one of – if not the most – extensive procurement ever undertaken in this province. Depending on what resources are ultimately procured, the province may continue to find itself with surplus supply in many hours. Additionally, how grids in neighbouring jurisdictions are changing will also have an impact on export flows from Ontario. Furthermore, exports can provide value even in hours when there is no surplus supply. See the answer to PA-SEC-11, where we show that congestion rents can accrue in hours where HOEP is well above $0/MWh and non-baseload supply is being dispatched.

2.2.2 See previous answer.

PA-VECC-3.0

Reference:
Power Advisory Evidence, page 9
Preamble:
The Evidence states:
"Hydro One's joint transmission and distribution application proposes increasing in the ETS rate from its current level of $1.85/MWh to $6.54/MWh (on an adjusted basis). An increase of this magnitude will impose additional costs on Ontario ratepayers, resulting in higher electricity-related charges for domestic ratepayers, while reducing the economic efficiency of the grid. The ETS rate acts as a transactional cost to export traders when engaging in energy trading. All else being equal, increasing the ETS rate increases the transactional cost of exporting energy from Ontario, results in less supply being exported, reduces congestion rents and increases curtailment of baseload supply. The net impact on Ontario's ratepayers is negative."
Question(s)

3.1 Please indicate where in its EB-2021-0110 Application Hydro One proposes that the ETS rate be increased to $6.54 (on an adjusted basis).

3.2 With respect to the first reference above, please explain what is meant by "all else being equal".

3.3 With respect to the first reference above, please confirm that based on the analysis presented in the Evidence (pages 38-39) increasing the ETS rate also increases overall ETS revenues which benefits Ontario ratepayers.

3.4 With respect to the first reference, does increasing the ETS result: i) in less supply being exported, ii) reduced congestion rents and iii) increased curtailment of baseload generation in all hours of the year?

3.4.1 If not, under what circumstances will each "result" occur?

3.4.2 If not, how many hours in each of the years 2018-2021 were the circumstances such that each of the claimed results would have occurred?

3.4.3 If yes, please explain why.

Response:

3.1 Hydro One is not proposing to increase it to that level. Power Advisory's evidence is in response to the Elenchus evidence, which includes an option to increase the ETS rate to that level.

3.2 Holding everything constant. Any change in a dynamic electricity market will result in numerous (in many cases unexpected) outcomes. We are trying to isolate one change – an increase in the ETS rate.

3.3 Agreed. A higher ETS rate results in greater revenue from export trades, but as noted in our report, results in negative financial impacts in other areas.

3.4 Based on our analysis, yes.

3.4.1 See previous example.

3.4.2 See previous example.

3.4.3 Our report describes this in detail.

PA-VECC-4.0

Reference:
Power Advisory Evidence, page 9
Exhibit I, Tab 5, Schedule 15.2
Preamble:
The Evidence states (page 9):
"A higher transaction cost will, in general, reduce exports in hours when it is economically advantageous to sell Ontario supply into neighbouring markets (i.e. when prices are lower in Ontario)".
The Evidence states (page 10);
"Increasing the ETS rate – which acts as a transactional cost – reduces the overall efficiency of energy trading and the province's electricity sector as a whole."
And
"Given that energy exports are a net benefit for Ontario ratepayers and do not impose any costs on Ontario ratepayers, the ETS rate should continue to be set at a low level to further enable the economic efficiency of energy trading."
Question(s)

4.1 What is meant by "when prices are lower in Ontario" (page 9)? Is this referring to hours when the Ontario HOEP is less that the price of electricity in the neighbouring market?

4.2 What does Power Advisory mean by the terms "the overall efficiency of energy trading" and "economic efficiency of energy trading"?

4.3 Please explain what Power Advisory means by "transactional costs".

4.4 Does Power Advisory consider congestion payments (based on ICP) and/or Uplift charges to be transactional costs?

4.4.1 If not, why not given they are also part of the cost of an export transaction?

4.4.2 If yes, does Power Advisory consider congestion payments to be inhibiting "economically advantageous sales from Ontario to neighbouring markets" and reducing "the overall efficiency of energy trading"?

4.4.3 If yes, does Power Advisory consider the levying of uplift charges to be inhibiting "economically advantageous sales from Ontario to neighbouring markets" and reducing "the overall efficiency of energy trading"? In responding please address the fact that a portion of the uplift charges does not vary with the level of exports. (per Exhibit I, Tab 5, Schedule 15.2).

Response:

4.1 When the wholesale price in Ontario is below that of neighbouring jurisdictions. If the intertie is congested, the congestion price would also have to be considered.

4.2 Energy trading should result in – to the greatest extent possible – energy moving to markets and consumers who value it most (a form of Pareto Optimality). Curtailment or spilling should be eliminated or reduced to the greatest extent possible and at the lowest cost.

4.3 The fixed cost of undertaking a trade – in this case, the fixed cost of undertaking an export trade.

4.4 No, as they are not fixed. In hours when congestion rents occur, they can be considered either a higher energy cost and or dynamic toll to allocate spare transmission capacity. In any case, they are not a fixed charge for each transaction, but are an economic signal to market participants.

4.4.1 See previous answer.

4.4.2 See previous answer.

4.4.3 See previous answer.

PA-VECC-5.0

Reference:
Power Advisory Evidence, pages 10 and 46-48
Preamble:
The Evidence states (page 10):
"Given that energy exports are a net benefit for Ontario ratepayers and do not impose any costs on Ontario ratepayers, the ETS rate should continue to be set at a low level to further enable the economic efficiency of energy trading."
In its final conclusions regarding a higher or lower ETS rate Power Advisory notes the impact of a higher or lower rate but does not make any specific recommendation regarding the appropriate level for the ETS rate.
Question(s)

5.1 By stating that "the ETS rate should continue to be set at a low level to further enable the economic efficiency of energy trading" is Power Advisory recommending that the ETS rate be maintained at its current level of $1.85/MWh?

5.2 If not, does Power Advisory have a recommendation as to the appropriate level for the ETS rates and, if so, what is it?

Response:

5.1 Power Advisory's analysis does not advocate for a particular ETS rate. Given the IESO's evidence on the benefits of export trading at the current rate, our analysis shows the impact of changing the ETS to a higher and a lower rate.

5.2 No, but we do want to highlight that a rate of $0/MWh would have increasedsystem-wide benefits. That said, a regulator can determine a rate based on a number of principles – i.e. fairness and transparency, among others. While one rate may produce the highest benefit, it may not be preferred by a regulator for other reasons.

PA-VECC-6.0

Reference:
Power Advisory Evidence, page 10 (Table 1)

Question(s)

6.1 Please confirm that the heading for the second column should read "Increasing ETS Rate to $6.54/MWh" and not "$4.69/MWh".

Response:

6.1 Confirmed.

PA-VECC-7.0

Reference:
Power Advisory Evidence, page 12
Preamble:
The Evidence states:
"Ultimately, a settlement agreement was reached between Hydro One and parties to the proceeding that included an ETS rate of $1.85/MWh (a simple average compromise between the $2/MWh rate in place and the $1.70 proposed by Elenchus)6". Footnote #6 states "See the Draft Rate Order for EB-2014-0357).
And
"The important takeaway from the history of the ETS rate is that determining the most "efficient" level has been subject to competing claims for nearly two decades and has never been set on an "economically efficient" basis."
Question(s)
7.1 With respect to the first reference, please indicate where in the Draft Rate Order for EB-2014-0357 it states the $1.85 was based on "a simple average compromise between the $2/MWh rate in place and the $1.70 proposed by Elenchus".

7.2 Please confirm that the Settlement Agreement filed in EB-2014-0140 and which established the $1.85 did not indicate that the $1.85 was arrived at as a result of simply averaging the $2/MWh rate in place and the $1.70 proposed by Elenchus.

7.3 With respect to the second reference, is it Power Advisory's view that setting the ETS rate should be based solely on considerations of economic efficiency (i.e., what is the most (economically) efficient level for the rate)?

7.3.1 If not, what other considerations should be taken into account when setting the ETS rate?

7.3.2 If not, how has Power Advisory taken these other considerations into account in drawing its conclusions and making its recommendations regarding the appropriate level for the ETS rate?

Response:
7.1 Power Advisory calculated the amount.

7.2 Agreed.

7.3. There are many definitions of economic efficiency. In this context of this proceeding, Power Advisory views economic efficiency as the allocation of resources to their most valuable use and the mitigation of waste or surplus to the greatest extent possible. Another definition that would be useful is the allocation of scarce resources to their most optimal use. In any case, generating and distributing energy to those who value it most and at the lowest possible cost (but no lower), should be a driving motivation of an electricity market.

In general, economic efficiency leads to the most productive use of an economy's resources. We view that as an optimal outcome in regards to Ontario's electricity grid.

7.3.1 Social and environmental policy can also be considered, among other factors.

7.3.2 No, Power Advisory's evidence focused on economic efficiency. That said, based on our analysis, increasing the ETS may result in higher costs for domestic customers.

PA-VECC-8.0

Reference:
Power Advisory Evidence, page 15
Preamble:
The Evidence states:
"When a greater number of trades are uneconomic, overall energy trading is reduced and the value of moving Ontario's energy supply to neighbouring jurisdictions decreases."
Question(s)

8.1 Apart from additional revenues from ETS rates, Uplift charges and congestion charges (i.e., ICP) and the avoided curtailment of baseload generation, does moving Ontario's energy supply to neighboring jurisdictions provide "value" to Ontario consumers/ratepayers?

8.1.1. If yes, please explain what the additional sources of "value" are and under what market/system conditions it will accrue to Ontario ratepayers?

Response:

8.1 "Apart from additional revenues from ETS rates, Uplift charges and congestion charges (i.e., ICP) and the avoided curtailment of baseload generation" is a significant caveat. In any case, there may also be an environmental benefit given Ontario's low emissions factor compared to a number of neighbouring jurisdictions (notably MISO and NYISO). Ontario, as has been well documented, has a lower marginal emissions factors compared to most neighbouring jurisdictions with wholesale electricity markets. Even when considering Manitoba and Quebec – both of which would have a lower marginal emissions factor than Ontario – energy will often flow through those grids to other jurisdictions – MISO, PJM, ISO-NE and New Brunswick.

8.1.1 As described, there may be an environmental benefit, but that does not provide a financial benefit, unless Ontario begins selling environmental credits based on real-time generation.

PA-VECC-9.0

Reference:
Power Advisory Evidence, page 15
Exhibit I, Tab 1, Schedule 29
Exhibit I, Tab 6, Schedule 3 and Schedule 4
Hydro One's ETS Submissions, Attachment 3, page 14
Preamble:
The Power Advisor Evidence states:
"The IESO evidence repeatedly notes the different market design of export pricing at the province's interties compared to other jurisdictions, which were discussed in both the Elenchus and CRA evidence. Ontario's dynamic design for determining congestion rents is not replicated in other markets and – given how material congestion rents have been in recent years – understates the true cost (and value to Ontario ratepayers) of exporting energy from Ontario into neighbouring jurisdictions."
CRA's response in Exhibit I, Tab 1, Schedule 29 states:
"In its review of ETS rates for 2020, CRA did not find any evidence that specific market based outcomes were considered in the setting of ETS rates".
CRA's response in Exhibit I, Tab 6, Schedule 4 states:
"CRA confirms that in American jurisdictions covered by the CRA Report, Exports as well as loads pay for energy on the basis of Locational Marginal Pricing (LMP) which also includes cost of congestion and losses."
In its initial submission (Attachment 3) the IESO states:
"Second, it is important to consider the benefits of Ontario's ICP design that dynamically adjusts to market conditions, compared to the 'point-to-point' model in many other US jurisdictions where exporters gain access to flow on a first-come, first-serve basis. In contrast to the ICP, the point-to-point model limits the collection of greater revenues beyond the ETS rate, even if exporters are willing to pay more. In this respect it can be seen that the ICP is a more effective mechanism with its fair allocation of access and dynamic adjustment to market conditions."
Question(s)

9.1 While Ontario's market design approach to determining congestion rent is not replicated in the other markets, does Power Advisory agree with CRA's comment (Exhibit I, Tab 6, Schedule 4) that for other markets the use of LMP means the costs of exports in these other markets also includes congestion rent/pricing?

9.1.1. If not, why not?

9.2 In these markets will the level of the ETS rate charged for exports impact the LMP at its interties?

9.2.1 If not, why not?

9.3 Does Power Advisory agree with CRA's response (Exhibit I, Tab 1, Schedule 29) that in the jurisdictions neighbouring Ontario specific market outcomes are not considered in the setting of ETS rates?

9.3.1 If not, please identify the jurisdictions where specific market outcomes are not considered in the setting of ETS rates and describe how this is done.

Response:

9.1 No. LMPs typically include energy, congestion and line losses. Congestion rents on Ontario's interties are set by competition among export bids.

9.1.1 CRA appears to confirm that most US wholesale electricity markets incorporate LMPs, which we agree with. It does not appear to state that the cost of energy at the intertie is based on exports bids as is the case at Ontario's intertie.

9.2 Power Advisory was not asked to undertake a detailed review of export pricing in neighbouring markets.

9.2.1 See previous answer.

9.3 Power Advisory did not undertake a detailed review of the setting of ETS rates in neighbouring jurisdictions.

9.3.1 See previous answer.

PA-VECC-10.0

Reference:
Power Advisory Evidence, pages 14, 16-18 and 54
Question(s)

10.1 What does Power Advisory understand to be the purpose of a cost allocation study?

10.2 In Power Advisory's view is there difference between "cost allocation" and "rate design" when it comes to the setting of: i) rates in general and ii) ETS rates in particular?

10.3 At page 54, under Professional Experience, Mr. Lusney's CV includes the following: "Represented through expert evidence and testimony the Utility Consumer Advocate Alberta during Transmission Rate Tariff hearing in front of the Alberta Utility Commission as an expert witness on transmission planning and cost allocation". Please provide the following: i) a copy of Mr. Lusney's evidence in the noted proceeding and ii) an internet link to where a record of proceeding and the AUC's decision can be found. Note: If there is no "link", please also provide a copy of the AUC's final decision.

10.4 With respect to Figure 1 (page 18), please confirm that the figure indicates the number of hours where the clearing price was at or below $0/MWh (as indicated in the title) and not the number of hours the clearing price was below $0/MWh (as indicated in the vertical axis' label).

10.5 With respect to Figure 1 (page 18), please provide a similar figure based on the number of hours the clearing price was at or below $5/MWh.

10.6 With respect to Figure 1 (page 18), please provide a breakdown as to the number of hours the clearing price was at or below $0/MWh for each of the years 2018, 2019, 2020 and 2021 for Ontario.

10.7 During the 2018-2021 period, did surplus baseload generation conditions exist in all of the hours when the clearing price was at or below $0/MWh in Ontario (per Figure 1)?

10.7.1 If not, what other market conditions led to the clearing price being at or below $0/MWh?

10.8 During the 2018-2021 period, was the Ontario clearing price at or below $0/MWh in Ontario in all hours when surplus baseload generation conditions existed in Ontario?

10.8.1 If not, why not?

10.9 During the 2018-2021 period, did surplus baseload generation conditions exist in all of the hours when the market clearing price was at or below $5/MWh?

10.9.1 If not, what other market conditions led to the clearing price being at or below $5/MWh?

10.10 During the 2018-2021 period was the Ontario clearing price at or below $5/MWh in all hours when surplus baseload generation conditions existed in Ontario?

10.10.1 If not, why not?

Response:

10.1 To allocate costs (and revenues) in a fair, causal, measurable, objective, stable, consistent, and straightforward manner.

10.2 Yes. Rate design can incorporate a number of considerations, including simplicity and transparency, as well as social and other broader considerations.

10.3 Please see the attached evidence of Power Advisory LLC together with the AUC's Decision 2014-242.

10.4 Confirmed.

10.5 This request requires Power Advisory to conduct significant work and would not significantly clarify the current analysis. As such, Power Advisory is not able to provide the requested information with reasonable effort, given the current timelines and amount of interrogatories. All of the information that Power Advisory used is publicly available.

10.6 This request requires Power Advisory to conduct significant work and would not significantly clarify the current analysis. As such, Power Advisory is not able to provide the requested information with reasonable effort, given the current timelines and amount of interrogatories. All of the information that Power Advisory used is publicly available.

10.7 The IESO does not provide publicly available data for SBG on an hourly basis.

10.7.1 See previous answer.

10.8 See previous answer

10.8.1 See previous answer

10.9 See previous answer

10.9.1 See previous answer

10.10 See previous answer

10.10.1 See previous answer

PA-VECC-11.0

Reference:
Power Advisory Evidence, pages 21-22
Preamble:
The Evidence states:
"When HOEP is $0/MWh or below, hydro supply remains, on average, around 3,000 MW – meaning it is offering a significant amount of supply at a price well below its marginal cost, which includes the Gross Revenue Charge (GRC), among other costs. In these hours, hydro generators are selling energy at a "loss" based on market prices. Selling supply at a "loss" reduces the economic efficiency of the wholesale market, but occurs often in Ontario as a combination of the hybrid design and surplus baseload supply".
Question(s)
11.1 Please explain how Figure 4 was created. As part of the response please provide a figure (i.e., a scatter diagram) that plots the hourly HOEP values against the MW of hydro supply used in the creation of Figure 1.

11.1.1 Based on this data is the increase in the MW of hydro supply as HOEP increases statistically significant?

11.2 What was the marginal cost of hydro supply over the period 2018-2021?

11.3 With respect to Figure 4, do the MW of hydro supply increase if the HOEP increases to levels higher than $15/MWh?

11.3.1 Does the level of hydro supply increase when HOEP rises to levels above the marginal cost of hydro supply? If yes, why?

11.4 Why does selling supply at a loss reduce economic efficiency, when the price is being set by the market?

Response:
11.1 Power Advisory compiled publicly available hourly hydro supply and HOEP data. All of the data used in the graph was pulled from the IESO's website.

11.1.1 Yes.

11.2 The marginal cost of hydro changes based on annual output. The Ontario government provides an overview of how Gross Revenue Charges (GRC). See: https://www.ontario.ca/document/gross-revenue-charges-hydroelectric-generating-stations#:~:text=The%20gross%20revenue%20charge%20is,to%20the%20Minister%20of%20Finance

11.3 Yes.

11.3.1 Yes, as there is some amount of hydro supply that is related to opportunity costs.

11.4 Market participants are receiving an out of market payments to make them financially whole. The market is not fully setting the price.

PA-VECC-12.0

Reference:
Power Advisory Evidence, page 22
Preamble:
The Evidence states:
"A significant amount of generating capacity in Ontario falls under OEB rate regulation – including OPG's nuclear assets at both the Darlington Nuclear Generating Station ("Darlington") and the Pickering Nuclear Generating Station ("Pickering"), as well as the heritage hydroelectric assets described previously. Nearly all other capacity in Ontario is signed to long-term contracts with the IESO, including the Bruce Nuclear Generating Station ("Bruce"), wind and solar generators and gas-fired generators. Both contracted and regulated assets are typically made financially whole for supply sold in the wholesale market. For example, output from a wind contract may be contracted with the IESO at $135/MWh – meaning it will be paid that amount for any MW it sells into the wholesale market. If HOEP is $10/MWh, it will receive a $125/MWh payment, which is recovered from ratepayers through the Global Adjustment".
Question(s)

12.1 For baseload supply (i.e., nuclear, must-run hydro and wind and solar) is the total compensation received the same under each of the following conditions: i) the generator chooses not to bid into the Ontario market, ii) the generator bids and the bid clears for sale into the Ontario market, iii) the generator bids and the bid does not clear for sale into the Ontario market, and iv) the generator bids, the bid clears for sale into the Ontario market but the generator is directed by the IESO to curtail (or maneuver) it generation?

12.1.1 If not, what are the differences and why? In the response, please distinguish by source of generation if required.

12.2 For baseload supply (i.e., nuclear, must-run hydro and wind and solar) is the net compensation received (i.e., total compensation less marginal costs) the same under each of the following conditions: i) the generator chooses not to bid into the Ontario market, ii) the generator bids and the bid clears for sale into the Ontario market, iii) the generator bids and the bid does not clear for sale into the Ontario market, and iv) the generator bids, the bid clears for sale into the Ontario market but the generator is directed by the IESO to curtail (or maneuver) it generation?

12.3 If not, what are the differences and why? In the response, please distinguish by source of generation if required.

Response:

12.1 Neither the IESO or market participants provide details on hourly settlement related to SBG or bid and offers. SBG typically occurs when there is surplus supply – based on Price-Quantity pairs – compared to demand. If a market participant does not offer into the market, Power Advisory's reading of the Market Rules and understanding of most contract structures is that it will not be compensated. If an offers is economic, it should be dispatched based on the economic merit order. If a generator is dispatched down as directed by the IESO it will received a CMSC for energy market revenues and be financially made whole through contract revenues. Power Advisory does not intend to walk through settlement for each resource type, given the variety of contract structures in place in Ontario.

12.1.1 See previous answer.

12.2 See previous answer.

12.3 See previous answer.

PA-VECC-13.0

Reference:
Power Advisory Evidence, page 23
Preamble:
The Evidence states:
"When baseload supply – the combination of nuclear, must-run hydro and wind and solar – exceeds domestic load, the province is experiencing Surplus Baseload Generation (SBG). SBG is resolved through two mechanisms. First, the energy is exported on an economic basis – i.e. energy traders purchase the energy in Ontario and sell it into a neighbouring market. Second – when SBG is more extreme – supply is either curtailed or spilled. Units at Bruce can be "maneuvered" down to reduce supply; water at hydro dams can be "spilled"; and wind and solar turbines can be "curtailed."
And
"The key point is that Ontario has a significant amount of baseload supply that will – in many hours – push HOEP below both the marginal cost of market participants, but also significantly below contracted or regulated rates."
Question(s)

13.1 Does the presence of a significant amount of baseload supply result in HOEP being below the marginal cost of all market participants or just some market participants for many hours of the year?

13.1.1 If all, please explain why.

13.2 Over the 2018-2021 period, what was the total amount of SBG annually and, in each year, how much of this was resolved through exports and how much was through managing (via nuclear maneuvering, wind and solar curtailment, etc.) supply?

13.3 Is SBG only resolved through curtailment, spill or maneuvering (i.e., the second of the two mechanisms discussed in the first reference) when exports ties are constrained and no more supply can be exported?

13.3.1 If not, please explain why.

13.4 What is Power Advisory's understanding as to the total amount of SBG that the IESO expects will occur annually over the 2023-2027 period that will need to be resolved through either exports or "managing" supply?

Response:

13.1 Some market participants. In a number of hours, HOEP can be set by thermal units (predominantly gas-fired units), which have a higher marginal cost than nuclear, wind, solar and most hydro units. Additionally, the price can be below the marginal cost for one unit, while simultaneously being above the marginal cost of another unit.

13.1.1 See previous answer

13.2 The IESO does not provide detailed SBG amounts.

13.3 Predominantly, yes.

13.3.1 See previous answer

13.4 The IESO expects it to decline due to the combination of the retirement of PNGS, nuclear refurbishments and increased demand. That said, the IESO is also undertaking multiple procurement processes – a number of which are explicitly targeting an in-service date of 2025. Additionally, given the ongoing economic uncertainty, a recession may reduce demand materially for a short or medium time period, leading to higher amounts of SBG.

PA-VECC-14.0

Reference:
Power Advisory Evidence, pages 24-26
Question(s)
14.1 What point in time is the data set out in Figure 5 based on?

14.2 Do Figures 5 and 6 include all of Ontario's hydro supply or just thea "must-run" hydro supply?

14.3 With respect to the figure on page 26, what period (i.e., time-frame) are the values based on?

14.4 With respect to the figure on page 26, for each of the jurisdictions please provide a scatter diagram that for the period used plots the frequency at which different hourly prices occur using intervals of $1 (i.e. frequency of prices in the $1-$2 range, the $2-$3 range, etc.)

Response:
14.1 2021

14.2 All of Ontario's supply.

14.3 2021

14.4 This request requires Power Advisory to conduct significant work and would not significantly clarify the current analysis. As such, Power Advisory is not able to provide the requested information with reasonable effort, given the current timelines and amount of interrogatories.

PA-VECC-15.0

Reference:
Power Advisory Evidence, pages 9 and 28-29
Preamble:
The Evidence states (page 9):
"The ETS rate acts as a transactional cost to export traders when engaging in energy trading. All else being equal, increasing the ETS rate increases the transactional cost of exporting energy from Ontario, results in less supply being exported, reduces congestion rents and increases curtailment of baseload supply".
Question(s)
15.1 With respect to Figure 8, if the ETS rate were to increase by $5/MWh would this lead to each of the bids shown in the Figure being $5 less?

15.1.1 If not, why not?

15.1.2 If yes, given such an event would the level of exports remain unchanged from that shown in Figure 8?

15.2 With respect to Figure 8, if the ETS rate were to decrease by $2/MWh would this lead to each of the bids shown in the Figure being $2 more?

15.2.1 If not, why not?

15.2.2 If yes, given such an event would the level of exports remain unchanged from that shown in Figure 8?

15.3 With respect to Figure 9, if the ETS rates were to increase by $5/MWh would this lead to each of the bids shown in the Figure being $5 less?

15.3.1 If not, why not?

15.3.2 If yes, given such an event would the level of exports remain unchanged but the ICP be reduced from $20/MWh to $15/MWh?

15.4 With respect to Figure 9, if the ETS rates were to decrease by $2/MWh would this lead to each of the bids shown in the Figure being $2 more?

15.4.1 If not, why not?

15.4.2 If yes, given such an event would the level of exports remain unchanged but the ICP be increased from $20/MWh to $22/MWh?

Response:
15.1 That is Power Advisory's assumption.

15.1.1 See previous answer.

15.1.2 No. Power Advisory assumes that market participants would respond to a $5/MWh increase in the ETS with a $5/MWh decrease in their export bid. As an example, if an exporter is willing to purchase energy at $15/MWh when the ETS charge is $0/MWh. If the ETS charge in increased to $5/MWh, the export bid will have to be lowered by $5/MWh.

15.2 Yes. See previous answer.

15.2.1 See previous answer.

15.2.2 See previous answer

15.3 See previous answer

15.3.1 See previous answer

15.3.2 See previous answer

15.4 See previous answer

15.4.1 See previous answer

15.4.2 See previous answer

PA-VECC-16.0

Reference:
Power Advisory Evidence, pages 31-32
Question(s)

16.1 With respect to paragraph 77 and Figure 10, has Power Advisory undertaken any analysis to determine if there is a "statistically" significant trend/relationship between the level of exports to NYISO and the NYISO/HOEP price spread?

16.1.1 If yes, what were the results?

16.2 Has Power Advisory investigated the relationship between the level of exports to other interconnected jurisdictions and the price spread between the HOEP and the hourly price in those jurisdictions?

16.2.1 If yes, is the relationship similar to that for the HOEP-NYISO price spread versus exports?

Response:

16.1 There is a lot of statistical "noise" when it comes to exports and prices. Power Advisory discussed this in a previous IR. Figure 14 ignores some of the pricing extremes and shows a much clear statistical relationship.

16.1.1 See previous answer.

16.2 Yes, but as noted in the evidence, there is a significant amount of "noise" that is inherent in a dynamic electricity market. Power Advisory's analysis provided a cleaner analysis using HOEP "buckets" as a proxy for an increase in the ETS charge. Secondly, it's not always clear what the "sink" is for the other side of an export trade. Having access to real-time bid behaviour would provide a clearer view on the impact of a higher ETS.

16.2.1 See previous answer.

PA-VECC-17.0

Reference:
Power Advisory Evidence, pages 5 and 35-37
Question(s)

17.1 Please explain how the "average export" line in Figure 13 was developed (e.g., were individual trend lines established for each of the $5 intervals?).

17.2 At page 5 the Evidence states that one of the issues that would be addressed was "a statistical analysis on the sensitivity of Ontario exports to price changes". Was the trend line shown in Figure 14 established using statistical analysis such as regression analysis?

17.1.1 If yes, what was the standard deviation associated with the relationship and is the trend statistically significant (i.e., is there a statistically significant relationship between changes in HOEP and the change in the level of exports)?

17.1.2 If not, please undertake a statistical analysis of the sensitivity of Ontario exports to change in the level of the HOEP based on the data set out in Figure 14 and report the results including the standard deviation associated with coefficient for HOEP.

17.3 At page 35 the Evidence states "Focusing on exports when prices are between $0/MWh and $50/MWh – which would incorporate the marginal cost of a majority of Ontario's supply mix – a $5/MWh increase in the Ontario price results in 160 MW reduction in hourly export volumes". Please provide a schedule setting out how the 160 MW was derived.

17.4 At pages 35-36 the Evidences states: "More importantly, looking at exports when the Ontario price moves from $0/MWh to $5/MWh – likely when Ontario is experiencing severe SBG and curtailment – hourly exports decrease, on average, by nearly 280 MW". Please provide a schedule setting out how the 280 MW was derived.

17.5 At page 35 the Evidence states: "But we need to be clear: there are a number of limitations with available public data compared to what is required to provide a highly accurate estimate price elasticity and system-wide benefits of exports." Given this qualification how accurate are the 160 MW and 280 MW estimates and what is the 50% confidence interval (based on the statistical analyses discussed above) that is associated with each?

Response:

17.1 It is average exports in every hour by pre-defined HOEP ranges.

17.2 It is a linear trendline and is simply there to show a high-level relationship between HOEP and exports at one intertie.

17.2.1 Please see previous answer.

17.2.2 Power Advisory declines to undertake the analysis.

17.3 Power Advisory declines to provide the schedule. As noted, the average hourly exports were calculated on pre-determined HOEP ranges. The 160 MW is the difference between two pre-determined HOEP ranges.

17.4 See previous answer.

17.5 These two figures do not materially impact Power Advisory's analysis. They are used a benchmark to understand the relationship between HOEP and exports.

PA-VECC-18.0

Reference:
Power Advisory Evidence, page 38
Preamble:
The Evidence states: "Congestion prices on the interties are also inversely related to HOEP. As HOEP moves higher, congestion rents decrease and vice versa. Looking at congestion rent in hours when HOEP ranges from $0/MWh to $20/MWh – which, again, incorporates the marginal cost of Ontario's baseload supply resources, including nuclear, hydro and wind/solar – a $5/MWh increase in the intertie price can reduce the congestion price by as much as $5/MWh on certain interties (notably on the Michigan intertie)."
Question(s)
18.1 Figure 15 is based on data from what period in time?

18.2 Are the values used to create Figure 15 based on all of the hours for this period, including those when there was no congestion rent?

18.2.1 If not, please re-do Figure 15 and include those hours.

18.3 For each of the five jurisdictions portrayed in Figure 15 please provide a scatter diagram (similar to Figure 14) that plots hourly values for congestion rent against the HOEP value in the same hour based on the data used to create Figure 15.

18.3.1. For each of the five jurisdictions, is the relationship between HOEP and Congestion Rent ($/MWh) statistically significant considering all values for HOEP in the $0/MWh to $20/MWh range?

18.3.2 For each of the five jurisdictions, is the relationship between HOEP and Congestion Rent ($/MWh) statistically significant considering all values for HOEP in the $0/MWh to $5/MWh range?

18.4 If Figure 15 did not include those hours when there was no congestion rent, then please provide a scatter diagram for each of the five jurisdictions that also includes those hours.

18.4.1 Based on this data, for each of the five jurisdictions, is the relationship between HOEP and Congestion Rent ($/MWh) statistically significant when all values for HOEP in the $0/MWh to $20/MWh range are considered?

18.4.2 Based on this data, for each of the five jurisdictions, is the relationship between HOEP and Congestion Rent ($/MWh) statistically significant considering all values for HOEP in the $0/MWh to $5/MWh range?

18.5 Based on the foregoing statistical analyses, what is the 50% confidence interval for the estimated $5 reduction in congestion rent due to a $5 increase in HOEP?

Response:

18.1 2018 – 2021.

18.2 Yes. This request requires Power Advisory to conduct significant work and would not significantly clarify the current analysis. As such, Power Advisory is not able to provide the requested information with reasonable effort, given the current timelines and amount of interrogatories. All of the information that Power Advisory used is publicly available.

18.3 This request requires Power Advisory to conduct significant work and would not significantly clarify the current analysis. As such, Power Advisory is not able to provide the requested information with reasonable effort, given the current timelines and amount of interrogatories. All of the information that Power Advisory used is publicly available.

18.3.1 See previous answer.

18.3.2 See previous answer.

18.4 This request requires Power Advisory to conduct significant work and would not significantly clarify the current analysis. As such, Power Advisory is not able to provide the requested information with reasonable effort, given the current timelines and amount of interrogatories. All of the information that Power Advisory used is publicly available.

18.4.1 See previous answer

18.4.2 See previous answer

18.5 This request requires Power Advisory to conduct significant work and would not significantly clarify the current analysis. As such, Power Advisory is not able to provide the requested information with reasonable effort, given the current timelines and amount of interrogatories. All of the information that Power Advisory used is publicly available.

PA-VECC-19.0

Reference:
Power Advisory Evidence, pages 38-39
Hydro One's ETS Submissions, Attachment 3, page 12
Exhibit I, Tab 6, Schedule 6 a)

Preamble:
In Attachment 3 the IESO states:
"Wide price spread between markets: occurs when there is a wider difference, or 'spread', between the price to buy electricity in Ontario and sell electricity in neighbouring jurisdictions. In this scenario an increase to the ETS will result in an offsetting decrease in ICP but no impact to export flows".
The response in Exhibit I, Tab 6, Schedule 6 a) states: "ICP is only applicable during times of congestion."

Question(s)

19.1 Please provide a schedule setting out how the 17 TWh reduction in exports sales based on a $4.69/MWh increase in the ETS rate was calculated (per paragraph 93). As part of the response please provide the source/basis for all inputs used.

19.2 How does Power Advisory's calculation of the decrease in export volumes due to an increase in the ETS rates account for the fact (per the IESO submissions, page 12) that an increase in the ETS rate will not impact export flows in hours when the ICP is greater than the ETS rate increase?

19.3 Please provide a schedule setting out how the $169.0 million reduction in congestion revenue based on a $4.69/MWh increase in the ETS rate was calculated. As part of the response please provide the source/basis for all inputs used.

19.4 How does Power Advisory's calculation of the decrease in congestion rents due to an increase in the ETS rates account for the fact (per the IESO response to Exhibit I, Tab 6, Schedule 6) that ICP is only applicable during times of congestion?

Response:

19.1 See attached methodology and spreadsheet.

19.2 See attached methodology and spreadsheet.

19.3 See attached methodology and spreadsheet.

19.4 See attached methodology and spreadsheet.

PA-VECC-20.0

Reference:
Power Advisory Evidence, pages 39-41
Preamble:
The Evidence states (page 40):
"Nearly all wind assets are signed to long-term, contract-for-difference (CfD) contracts with the IESO. A CfD contract pays a wind asset owned a fixed rate for every MWh of supply. Many of the CfD rates are set at $135/MWh or greater (due to inflation clauses in the contract)".
And
"Given the lack of hourly curtailment amounts, Power Advisory estimates wind curtailment by comparing forecasted versus actual output in hours when HOEP is below $5/MWh."
The Evidence states (page 41):
"Using the previous methodology to calculate curtailment payments, average annual wind curtailment costs Ontario ratepayers around $200 million annually (recognizing this is a high-level estimate).
Question(s)
20.1 Please provide a schedule that sets out Power Advisory's calculation of $200 million as being the annual cost of wind curtailment.

20.2 Is $135/MWh used by Power Advisory in determining the $200 million estimate for the annual cost of curtailing wind (paragraph 100)?

20.2.1 If yes, please indicate the source of this value and provide supporting references that indicate most wind contracts are based on CfD rates using this (or a higher) value.

20.2.2 If not, what $/MWh cost for wind curtailment was used and what was it based on?

20.3 Please explain why comparing forecasted versus actual output for wind is reasonable way to estimate curtailment. Could the change between forecast and actual wind output also be due to changes in weather and wind patterns as between forecast and actual?

20.4 Over what years was the average annual value of $200 million calculated?

20.4.1 If more than one year, please provide the estimated annual values for each year.

Response:
20.1 See attached methodology and spreadsheet.

20.2 VECC should ask the IESO to release contract details, as there is limited public information. In any case, see the Auditor General's 2011 report: https://www.auditor.on.ca/en/content/annualreports/arreports/en11/303en11.pdf

20.2.1 See previous answer.

20.2.2 Power Advisory used $135/MWh for curtailment, but that is not what our analysis shows. If a wind facility is curtailed rather than being exported, the additional cost to Ontario ratepayers is simply the wholesale market revenues that no longer accrue via the export. Given most curtailment occurs in hours when price is below $5/MWh, the amounts avoided are low.

20.3 There is currently no public data regarding curtailment. Curtailment of wind facilities should only occur when they are "uneconomic" – i.e. their energy offer is greater than HOEP. Given the marginal cost of wind resources is near $0/MWh, most curtailment should only occur in those hours. Power Advisory increased the threshold to $5/MWh to account for local constraints and other system operator actions. Power Advisory's estimates are directionally similar to the annual figures published by the IESO. Power Advisory agrees that forecasted and actual output could diverge for a number of reasons. One of those reasons could be curtailment, which is why that methodology was used.

20.4 2018 – 2021.

20.4.1 This request requires Power Advisory to conduct significant work and would not significantly clarify the current analysis. As such, Power Advisory is not able to provide the requested information with reasonable effort, given the current timelines and amount of interrogatories. All of the information that Power Advisory used is publicly available.

PA-VECC-21.0

Reference:
Power Advisory Evidence, page 41
Preamble:
The Evidence states:
"A higher ETS will reduce exports in hours when the province is curtailing wind supply (and vice versa). Relying on Power Advisory's estimate of wind curtailment, a higher ETS will result in as much as 7.6 TWh of increased wind curtailment between 2018 and 2021. Given that curtailment only occurs (in our model) when HOEP is $5/MWh or below, the financial impact to Ontario ratepayers totals as much as - $17.9 million over that time frame".
Question(s)
21.1 Is the "higher" ETS rate referred to $6.54/MWh (an increase of $4.69/MWh)? If not, what is the higher rate?

21.2 Please provide a schedule setting out Power Advisory's calculation that the higher ETS rate will result in "as much as 7.6 TWh of increased wind curtailment between 2018 and 2021".). As part of the response please provide the source/basis for all inputs used.

21.2.1 Please explain what is meant by "as much as". Did the Power Advisory model provide a range for the estimated amount of increased wind curtailment and, if so, what was the "range"?

21.3 Please provide a schedule setting out Power Advisory's calculation of the $17.9 M increase in curtailment costs as result of the modelled increase in the ETS rate. As part of the response please provide the source/basis for all inputs used.

Response:
21.1 Yes.

21.2 The information is included in the attached sheets and description.

21.2.1 Power Advisory recognizes that its approach for curtailment is an estimate based on its previously described methodology.

21.3 This request requires Power Advisory to conduct significant work and would not significantly clarify the current analysis. As such, Power Advisory is not able to provide the requested information with reasonable effort, given the current timelines and amount of interrogatories. All of the information that Power Advisory used is publicly available.

PA-VECC-22.0

Reference:
Power Advisory Evidence, pages 23, 33 (Figure 11), 38
(Figure 15) and 40-41
Hydro One's ETS Submissions, Attachment 3, page 12
Preamble:
The Evidence states (per page 23):
"When baseload supply – the combination of nuclear, must-run hydro and wind and solar – exceeds domestic load, the province is experiencing Surplus Baseload Generation (SBG). SBG is resolved through two mechanisms. First, the energy is exported on an economic basis – i.e. energy traders purchase the energy in Ontario and sell it into a neighbouring market. Second – when SBG is more extreme – supply is either curtailed or spilled. Units at Bruce can be "maneuvered" down to reduce supply; water at hydro dams
can be "spilled"; and wind and solar turbines can be "curtailed."
The Evidence states (page 41):
"A higher ETS will reduce exports in hours when the province is curtailing wind supply (and vice versa). Relying on Power Advisory's estimate of wind curtailment, a higher ETS will result in as much as 7.6 TWh of increased wind curtailment between 2018 and 2021. Given that curtailment only occurs (in our model) when HOEP is $5/MWh or below, the financial impact to Ontario ratepayers totals as much as - $17.9 million over that time frame".
In Attachment 3 the IESO states:
""'Wide price spread between markets: occurs when there is a wider difference, or 'spread', between the price to buy electricity in Ontario and sell electricity in neighbouring jurisdictions. In this scenario an increase to the ETS will result in an offsetting decrease in ICP but no impact to export flows".
Figure 15 in the Evidence indicates that when HOEP is at $5/MWh or less the congestion rent averages in excess of $15/MWH on the Michigan interties and in excess of $5/MWh on the New York interties. Figure 11 shows the Michigan and New York account for most of Ontario's exports.
Question(s)
22.1 At a HOEP of $5/MWh or less will wind generation only be curtailed when the interties are congested and no more surplus baseload generation can be exported?

22.1.1 If not, under what other circumstances would wind generation need to be curtailed?

22.2 According to Power Advisory's model wind curtailment occurs when HOEP is $5/MWh or less. However, according to Figure 15 the average congestion rent on the interties with Michigan and New York (Ontario's two largest export markets) is greater than $5/MWh when HOEP is in this range. Furthermore, at this level of ICP the IESO's evidence is that an increase in ETS rates of $5/MWh would reduce the ICP but have no impact on export flows. Does this mean that, in many instances, an increase in ETS rate of $5.00/MWh would not reduce exports during times of surplus wind generation and therefore would not lead to increased curtailment of wind generation?

22.2.1 If not, why not?

22.2.2. If yes, how has this been taken into account in Power Advisory's calculation that wind generation curtailment would increase by "as much as 7.6 TWh" between 2018 and 2021 if the ETS rate increased by $5/MWh?

Response:

22.1 In Power Advisory's view, that is likely.

22.1.1 See previous answer.

22.2 It may be offset by a reduction in congestion rent or curtailed.

22.2.1 The reduction in congestion rent is directly tied to the reduction in the economic viability of an export based on its bid. The increased ETS may alleviate congestion due to a decline in the economic viability of export trades. As a result, it can produce both lower congestion rents and reduced exports. A (very simplified) example may help illustrate this result

In the following example, we highlight two scenarios: one with an ETS of $0/MWh (Scenario A) and one with an ETS of $5/MWh (Scenario B). In Scenario A, 5 MW of exports flow and the Intertie Congestion Price (ICP) is $4/MWh, as export bids are stacked from highest to lowest, with the export bid of $4/MWh hitting the physical limit of the intertie. In Scenario B, the ETS is raised to $5/MWH and all exports bids would include this in their final bid (Energy Bid + ETS). Given the higher ETS, most bids would need a much lower HOEP to be economic. As such, only 3 MWs of exports bids are economic. The end result is both a reduction in congestion rent – as the intertie is no longer congested – as well as a reduction in export volumes.

HOEP	Scenario A: ETS at $0/MWh	Scenario B: ETS at $5/MWh	Physical Bid (MW)	Energy Bid ($/MWh)	Scenario A Energy Bid + ETS	Scenario B Energy Bid + ETS	Scenario A Economic	Scenario B Economic	TX limit (MW)
$1	$0	$5	1	$1	$1	($4)	Y	N	5
$1	$0	$5	1	$2	$2	($3)	Y	N	5
$1	$0	$5	1	$3	$3	($2)	Y	N	5
$1	$0	$5	1	$4	$4	($1)	Y	N	5
$1	$0	$5	1	$5	$5	$0	Y	N	5
$1	$0	$5	1	$6	$6	$1	Y	Y	5
$1	$0	$5	1	$7	$7	$2	Y	Y	5
$1	$0	$5	1	$8	$8	$3	Y	Y	5

22.2.2 See previous answer.

PA-VECC-23.0

Reference:
Power Advisory Evidence, pages 41-42
Preamble:
The Evidence states (page 41):
"A higher ETS will also impact exports of regulated hydro supply, which given the regulated rate of $43/MWh and the surplus baseload variance account that makes OPG financially whole for any spilled energy, will increase system-wide costs for Ontario ratepayers. Power Advisory's analysis focused on the impact to exports when HOEP moves from $15/MWh to $20/MWh – mimicking the increase a higher ETS will have on exports. The reason the analysis focuses on this range in the economic merit order is that this is the threshold where the marginal cost of OPG's large hydro assets either experience surplus supply (and will target exports) compared to being economically dispatched".
The Evidence states (page 42):
"Power Advisory's analysis assumes that the decrease in exports when HOEP increases from $15/MWh to $20/MWh – which is a proxy for an increase in the ETS rate of $5/MWh – results in a 4.1 TWh reduction in hydro exports over the 2018 – 2021 time frame and increase in spilled energy. The cost to Ontario ratepayers is $14.40 MWh for every unit of energy that is spilled and not exported."
Question(s)
23.1 Please provide a schedule that sets out Power Advisory's calculation of the 4.1 TWh reduction in hydro exports due to an increase in the ETS rate of $5/MWh. As part of the response please provide the source/basis for all inputs used.

23.2 Please provide a schedule setting out Power Advisory's calculation of the $14.40/MWh cost for every unit of hydro energy that is spilled. As part of the response please provide the source/basis for all inputs used.

Response:
23.1 The hydro calculation is based on exports, not hydro production, as described in the evidence.

23.2 This is Power Advisory's working assumption on the marginal cost of hydro. As noted extensively through our evidence and responses, the lack of data related to hourly curtailment amounts (and costs), as well as bid and offer data undermines transparency and the true cost of curtailment in Ontario.

PA-VECC-24.0

Reference:
Power Advisory Evidence, pages 23, 33 (Figure 11), 38 (Figure 15) and 41-42
Hydro One's ETS Submissions, Attachment 3, page 12

Preamble:
The Evidence states (per page 23):
"When baseload supply – the combination of nuclear, must-run hydro and wind and solar – exceeds domestic load, the province is experiencing Surplus Baseload Generation (SBG). SBG is resolved through two mechanisms. First, the energy is exported on an economic basis – i.e. energy
traders purchase the energy in Ontario and sell it into a neighbouring market. Second – when SBG is more extreme – supply is either curtailed or spilled. Units at Bruce can be "maneuvered" down to reduce supply; water at hydro dams can be "spilled"; and wind and solar turbines can be "curtailed."
The Evidence states (page 42):
"Power Advisory's analysis assumes that the decrease in exports when HOEP increases from $15/MWh to $20/MWh – which is a proxy for an increase in the ETS rate of $5/MWh – results in a 4.1 TWh reduction in hydro exports over the 2018 – 2021 time frame and increase in spilled energy."
In Attachment 3 the IESO states:
""Wide price spread between markets: occurs when there is a wider difference, or 'spread', between the price to buy electricity in Ontario and sell electricity in neighbouring jurisdictions. In this scenario an increase to the ETS will result in an offsetting decrease in ICP but no impact to export flows".
Figure 15 in the Evidence indicates that when HOEP is between $15/MWh and $20/MWh the congestion rent averages well in excess of $5/MWH on the Michigan intertie and around $5/MWh on the New York interties. Figure 11 shows the Michigan and New York account for most of Ontario's exports.

Question(s)

24.1 According to Power Advisory's model hydro spill occurs when HOEP increases from $15/MWh to $20/MWh. However, according to Figure 15 the average congestion rent on the interties with Michigan and New York (Ontario's two largest export markets) is generally equal to or greater than $5/MWh when HOEP is in this range. Furthermore, at this level of ICP the IESO's evidence is that an increase in ETS rates of $5/MWh would reduce the ICP but have no impact on export flows. Does this mean that, in many instances, an increase in ETS rate of $5.00/MWh would not reduce exports during times of surplus hydro generation (but rather reduce the ICP) and therefore would not lead to an increase in spilled energy?

24.1.1 If not, why not?

24.1.2 If yes, how has this been taken into account in Power Advisory's calculation that an increase in the ETS rate of $5/MWh would result in a reduction of 4.1 TWh of hydro exports over the 2018-2021 time frame and correspondingly increase spill hydro energy?

Response:

24.1 See previous response to VECC 22.

24.1.1 See previous response to VECC 22.

24.1.2 See previous response to VECC 22.

PA-VECC-25.0

Reference:
Power Advisory Evidence, page 42
Preamble:
The Evidence states:
"And finally, reduced exports – any point on the economic merit order – results in less market revenue paid by export traders. This reduces total market revenues and – due to the fixed cost nature of Ontario's electricity grid – increases total system costs for Ontario ratepayers. Based on historical export flows at different prices, our analysis estimates that the reduction in exports will result in a reduction in market revenues from exports of $40.8 million".
Question(s)
25.1 Please explain what market revenue (over and above that from ETS rates and congestion rent) the reference is referring to in terms of both the sources of revenues and who they are paid to (i.e. generators, Ontario consumers, etc.).

25.2 Please provide a schedule setting out the Power Advisory analysis that shows a $40.8 million reduction in market revenues from reduced exports due to a higher ETS rate. As part of the response please provide the source/basis for all inputs used.

Response:
25.1 Market revenue refers to the Market Clearing Price or HOEP multiplied by the number of exports in question.

25.2 See attached.

PA-VECC-26.0

Reference:
Power Advisory Evidence, page 44
Question(s)

26.1 Please provide a schedule that sets out Power Advisory's calculation that a $1.85 reduction in the ETS rate would result in an increase of more than 10 TWh in exports over the 2018-2021 period. As part of the response please provide the source/basis for all inputs used.

26.2 Please confirm that during those times in the 2018-2021 period when an intertie was congested, reducing the ETS rate would not have increased export sold over the intertie.

26.2.1 If not confirmed, please explain why.

26.2.2 If confirmed, please explain how the calculation of the export increase took this into account.

26.3 Please provide a schedule that sets out Power Advisory's analysis that a $1.85/MWh reduction in the ETS rate would along with the calculated 10 TWh increase in exports have increased congestion rents by $111.0 million. As part of the response please provide the source/basis for all inputs used.

26.4 How does Power Advisory's calculation of the increase in congestion rents due to a decrease in the ETS rates account for the fact (per the IESO response to Exhibit I, Tab 6, Schedule 6) that ICP is only applicable during times of congestion?

Response:

26.1 All data used in the analysis comes from the IESO website or S&P (for US wholesale market prices). The increase/decrease in exports is based on total exports in the different price ranges – i.e., if exports were 1 MWh when HOEP was $1/MWh and 2 MWh when HOEP was $0/MWh, the impact of a reduction in the ETS on exports would be 1 MWh. See the methodology attachment.

26.2 Not confirmed.

26.2.1 See the response to PA-VECC 22.

26.2.2 Not applicable.

26.3 See the response to PA-VECC-26.1.

26.4. It is based on historical actuals, which would have included that phenomenon.

PA-VECC-27.0

Reference: Power Advisory Evidence, page 45
Preamble: The Evidence states:
"Power Advisory estimated the amount of wind curtailment that occurs when HOEP is between $0/MWh and $1.85/MWh. The analysis assumes that given the significant decline in export volumes in that range, some portion of wind curtailment would have been avoided with the lower ETS rate. Power Advisory's analysis finds that as much as 5.8 TWh of potential curtailment could have been avoided. Given the inherent uncertainty of wind curtailment, Power Advisory assumes that only 50% of that curtailment should be counted and the average market revenue would be $0.92/MWh. In total, the cost savings to Ontario ratepayers is $4.9 million".
Question(s)

27.1 Please provide the supporting calculations for Power Advisory's determination that "as much as 5.8 TWh of potential wind curtailment could have been avoided" if the ETS rate was reduced from $1.85/MWh to $0/MWh. As part of the response please provide the source/basis for all inputs used.

27.2 What is the basis for Power Advisory's assumption that only 50% of the curtailment should be counted?

27.3 Please provide a schedule that sets out the determination of the $0.92/MWh in average market revenue. As part of the response please provide the source/basis for all inputs used.

Response:

27.1 All sources of information are from the IESO's publicly available data. See our attached methodology.

27.2 This is a high-level estimate, as there is no publicly available data to show what amount of curtailment would be avoided. Power Advisory's evidence repeatedly calls for an improvement in publicly available data – similar to what occurs in other competitive wholesale markets. The lack of currently available data limits the ability of ratepayers and other market participants to have a clear view on the hourly dispatch of the wholesale market.

27.3 This is simply the average of $0 - $1.85. Power Advisory assumes that not all curtailments would occur at either $0/MWh or $1.85/MWh.

PA-VECC-28.0

Reference:
Power Advisory Evidence, pages 23, 33 (Figure 1138 (Figure 15), 41 and 45
Hydro One's ETS Submissions, Attachment 3, page 12

Preamble:
The Evidence states (per page 23):
"When baseload supply – the combination of nuclear, must-run hydro and wind and solar – exceeds domestic load, the province is experiencing Surplus Baseload Generation (SBG). SBG is resolved through two mechanisms. First, the energy is exported on an economic basis – i.e. energy traders purchase the energy in Ontario and sell it into a neighbouring market. Second – when SBG is more extreme – supply is either curtailed or spilled. Units at Bruce can be "maneuvered" down to reduce supply; water at hydro dams can be "spilled"; and wind and solar turbines can be "curtailed."
The Evidence states (page 45):
"Power Advisory estimated the amount of wind curtailment that occurs when HOEP is between $0/MWh and $1.85/MWh. The analysis assumes that given the significant decline in export volumes in that range, some portion of wind curtailment would have been avoided with the lower ETS rate. Power Advisory's analysis finds that as much as 5.8 TWh of potential curtailment could have been avoided.".
In Attachment 3 the IESO states:
"“Wide price spread between markets: occurs when there is a wider difference, or 'spread', between the price to buy electricity in Ontario and sell electricity in neighbouring jurisdictions. In this scenario an increase to the ETS will result in an offsetting decrease in ICP but no impact to export flows".
Figure 15 in the Evidence indicates that when HOEP is at $5/MWh or less the congestion rent averages in excess of $15/MWh on the Michigan interties and in excess of $5/MWh on the New York interties. Figure 11 shows the Michigan and New York account for most of Ontario's exports.

Question(s)

28.1 According to Power Advisory's model wind curtailment occurs when HOEP is $5/MWh or less (Evidence, page 41). Also, according to Power Advisory's Evidence (page 23), wind curtailment occurs when exports are constrained and unable to fully resolve surplus baseload generation. However, according to Figure 15 the average congestion rent on the interties with Michigan and New York (Ontario's two largest export markets) is greater than $5/MWh hen HOEP is in this range and at this level of ICP the IESO's evidence suggests that a decrease in ETS rates of $1.85/MWh would increase the ICP but have no impact on export flows. Does this mean that, in many instances, a decrease in ETS rate to zero would not increase exports during times of surplus wind generation (but rather increase the ICP) and therefore would not lead to decreased curtailment of wind generation?

28.1.1 If not, why not?

28.2 If yes, how has this been taken into account in Power Advisory's calculation that wind generation curtailment would decrease by "as much as 5.8 TWh" between 2018 and 2021 if the ETS rate was decreased to zero?

Response:

28.1 No.

28.1.1 See the previous answer to PA-VECC-22.

28.2 See the previous answer to PA-VECC-22.

PA-VECC-29.0

Reference:
Power Advisory Evidence, page 45
Preamble:
The Evidence states:
"A lower ETS will also impact exports of regulated hydro supply. Similar to the previous analysis, Power Advisory's analysis focused on the impact to exports when HOEP declines by $1.85/MWh within the $14.40MWh - $16.25/MWh range, which would capture spill at large rate-regulated hydroelectric assets. There is a significant increase in export volumes when HOEP is decreased by
$1.85/MWh within that range – meaning that a material amount of supply that may have been spilled would instead be exported. The benefit to ratepayers is more than $58.2 million over the 2018-2021 time period."
Question(s)
29.1 Please provide the calculations underpinning the Power Advisory analysis that "there is a significant increase in export volumes when HOEP is decreased by $1.85/MWh within that range" (i.e., $14.40MWh - $16.25/MWh). As part of the response please provide the source/basis for all inputs used and the actual calculated in increase in exports.

29.2 Please provide a schedule that sets out the determination of the $58.2 million benefit to rate payers from reduce hydro spillage. As part of the response please provide the source/basis for all inputs used and explain how Power Analysis determined the amount of increased hydro generation (i.e., reduced hydro spill) that would result from the increase in exports.

Response:
29.1 Power Advisory declines to provide this information, as it is publicly available.

29.2 See previous answer.

PA-VECC-30.0

Reference:
Power Advisory Evidence, pages 23, 33 (Figure 11), 38
(Figure 15) and 44
Hydro One's ETS Submissions, Attachment 3, page 12
Preamble:
The Evidence states (per page 23):
"When baseload supply – the combination of nuclear, must-run hydro and wind and solar – exceeds domestic load, the province is experiencing Surplus Baseload Generation (SBG). SBG is resolved through two mechanisms. First, the energy is exported on an economic basis – i.e. energy traders purchase the energy in Ontario and sell it into a neighbouring market. Second – when SBG is more extreme – supply is either curtailed or spilled. Units at Bruce can be "maneuvered" down to reduce supply; water at hydro dams can be "spilled"; and wind and solar turbines can be "curtailed."
The Evidence states (page 45):
""A lower ETS will also impact exports of regulated hydro supply. Similar to the previous analysis, Power Advisory's analysis focused on the impact to exports when HOEP declines by $1.85/MWh within the $14.40MWh - $16.25/MWh range, which would capture spill at large rate-regulated hydroelectric assets. There is a significant increase in export volumes when HOEP is decreased by $1.85/MWh within that range – meaning that a material amount of supply that may have been spilled would instead be exported. The benefit to ratepayers is more than $58.2 million over the 2018-2021 time period."
In Attachment 3 the IESO states:
""Wide price spread between markets: occurs when there is a wider difference, or 'spread', between the price to buy electricity in Ontario and sell electricity in neighbouring jurisdictions. In this scenario an increase to the ETS will result in an offsetting decrease in ICP but no impact to export flows".
Figure 15 in the Evidence indicates that when HOEP is in the $15/MWh the congestion rent averages well in excess of $5/MWH on the Michigan intertie and around $5/MWh on the New York interties. Figure 11 shows the Michigan and New York account for most of Ontario's exports.
Question(s)
30.1 Power Advisory's analysis focused on the impact to exports when HOEP declines by $1.85/MWh within the $14.40MWh - $16.25/MWh range. However, according to Figure 15 the average congestion rent on the interties with Michigan and New York (Ontario's two largest export markets) appears to be equal to or greater than $5/MWh when HOEP values are in this range and at this level of ICP the IESO's evidence is that a decrease in ETS rates of $5/MWh would increase the ICP but have no impact on export flows. Does this mean that, in many instances, and decrease in the ETS rate of $1.85/MWh would not reduce exports during times of surplus hydro generation (but rather increase the ICP) and therefore would not lead to a decrease in spilled energy?

30.1.1 If not, why not?

30.1.1 If yes, how has this been taken into account in Power Advisory's calculation that a decrease in the ETS rate of $51.85/MWh would result in an increase in hydro energy based exports and a decrease in hydro energy spilled over the 2018-2021 time frame?

Response:

30.1 See answer to PA-VECC22.

30.1.1 See previous response

30.1.2 See previous response

PA-VECC-31.0

Reference:
Power Advisory Evidence, pages 42-43 and 46-47
Preamble:
The Evidence states (page 46)
"The time period of this analysis includes a significant and unforeseen event (the COVID-19 pandemic) that resulted in an unprecedented shutdown of large parts of the Ontario and global economies. The subsequent decline in energy consumption resulted in material instances of SBG in Ontario and surplus generating capacity in neighbouring jurisdictions. We have chosen not to remove these years (2020 and 2021) from the analysis, as we believe they provide a clear example of the benefits of the province's interties and the dynamic nature of export pricing in dealing with unforeseen events."
The Evidence states (page 47):
"Since market opening, two significant domestic demand decreases have occurred (i.e., financial crisis 2008, COVID-19 pandemic). During these time periods, exports quickly helped manage supply/demand balance and mitigate the risk of enacting more expensive measures (e.g., curtailment of supply). Erecting unnecessary barriers to exports will provide a consistent disincentive to exports which removes critical tools in Ontario's tool kit to managing unforeseen system conditions. We cannot predict when the next domestic demand decrease will occur, only that it will happen and the system should be designed to ensure options are available for system operators and market participants for the benefit of Ontario ratepayers."
Question(s)

31.1 Please provide a schedule that breaks out the impacts set out in Table 3 for each of the years 2018-2021.

31.2 Please provide a schedule that breaks out the impacts set out in the Table on page 46 for each of the years 2018-2021.

31.3 Are there unforeseen events that could occur and result in a significant reduction in both the surplus baseload generation in Ontario and congestion on Ontario's interties?

31.3.1 If not, why not?

31.4 Both references appear to characterize the need to maintain a low (or even lower) ETS rate as insurance that will assist in managing periods of lower than expected demand. Is this a fair characterization?

31.4.1 If not, why not?

31.4.2 Should consideration be given to how much this "insurance" costs in periods when load is at expected (or higher than expected) levels and whether the "cost" is appropriate in light of the risk? How would Power Advisor recommend the OEB address this issue?

Response:

31.1 See attached. All of the data used in the analysis is provided, while the methodology was provided in Appendix A. We have provided a more detailed description of the methodology.

31.2 See previous answer.

31.3 Possibly. Delays or unforeseen outcomes in the nuclear refurbishment program may result in a significant amount of baseload supply remaining offline. This would likely reduced SBG, increase HOEP, lower export volumes and lower congestion on the interties.

31.3.1 Not applicable.

31.4 To some extent, yes. But we believe it's more than an insurance policy. The current pricing structure on the interties is transparent and competitive, while generating a significant amount of revenue for Ontario ratepayers and providing operational flexibility. Shifting a larger portion of fixed system costs to the interties will reduce competition (via lower export volumes), lower congestion rents and impact operational flexibility. As our analysis shows, the potential for Ontario ratepayers to be worse off is a real possibility.

31.4.1 See previous answer.

31.4.2 As noted, we do not agree with the characterization that export customers are "free riders", though we recognize that a $0/MWh ETS rate in hours when there is no congestion can be viewed as such. Given the large amount of congestion rent and TR auction revenues, export customers provide a significant amount of revenue outside of the ETS. They also provide operational flexibility, which our evidence highlights also provides financial value to Ontario. The benefits more than offset the free rider concern, in our view. Overall, we view markets as a means to efficiently allocate resources – and the current pricing mechanism on the interties does exactly this, while providing value to Ontario ratepayers.

PA-VECC-32.0

Reference:
Power Advisory Evidence, page 47
Preamble:
The Evidence states:
"The future of Ontario's electricity market may be very different than the last ten years, when the province experienced significant amounts of SBG and curtailment. The IESO's current forecast expects SBG to decline materially with the closure of Pickering in 2026. But the future is very much unknown and thousands of MWs of new capacity is likely to be added to the province's grid over the next decade. Depending on what type of supply is added, the risk of SBG may far higher than the IESO is currently forecasting. For example, the IESO is expected to procure new capacity on an Unforced Capacity (UCAP) basis, which may result in significant oversupply from intermittent generators in many hours. Also, recent procurement programs for the IESO – along with plans for Small Modular Reactors (SMRs) and large hydro facilities in the north – are still in their infancy".
Question(s)
32.1 Is it not reasonable to expect that the IESO will consider the implications with respect to surplus baseload generation when deciding what types of resources should be procured in the future?

32.1.1 If not, why not?

32.2 Please provide references for the following statements and indicate the specific timeframe in which each of the procurement activities is expected to occur: i) "and thousands of MWs of new capacity is likely to be added to the province's grid over the next decade", ii) "the IESO is expected to procure new capacity on an Unforced Capacity (UCAP) basis, which may result in significant oversupply from intermittent generators in many hours" and iii) "recent procurement programs for the IESO – along with plans for Small Modular Reactors (SMRs) and large hydro facilities in the north – are still in their infancy".

Response:
32.1 No, it's no reasonable to expect this at all. The IESO must respond to policy directives that may create SBG conditions. The past decade of procurement is a perfect example of ongoing procurement in a time when new capacity was not needed. Additionally, a number of procurements – notably that of SMRs – comes almost exclusively from the provincial government, not the IESO.

32.1.1 See previous answer.

32.2 All of the listed references are on the IESO website. The IESO is launching both medium-term and long-term RFPs for new supply. The amount of MWs is in the thousands when combined across procurements. The IESO has publicly stated that it is procuring on an unforced basis. The SMR procurement will be included in OPG's rate-regulated assets. OPG has been asked by the provincial government to consider hydroelectric facilities in the north, but nothing has been formally approved.

INTERROGATORIES OF THE LONDON PROPERTY MANAGEMENT ASSOCIATION

PA-LPMA-1

Ref: Power Advisory Evidence, para. 72

a) Please explain how congestion rents are used to fund transmission expansion, particularly with respect to funding an economic buildout of intertie capacity.
b) What is the expected impact on congestion rents of additional intertie capacity? In particular, if additional intertie capacity increases the level of exports but also reduces the intertie congestion price, would congestion rents be expected to increase or decrease relative to the current level of intertie capacity?
c) What would be the expected impact on ETS revenues of additional intertie capacity?

Response:

a) See previous answer. Congestion rents are not currently used to fund transmission expansion, but could in a perfectly efficient market be used to expand transmission capacity.

b) All else being equal, they would decline.

c) Assuming the expanded intertie capacity is a result of high export demand, it would be expected to increase total export volumes and ETS revenues.

PA-LPMA-2

Ref: Power Advisory Evidence, para. 73 & 74
The evidence states that the fixed ETS is a low transaction cost and encourages bidding behaviour by market participants to determine the value of both the interties and real-time supply between Ontario and other markets.

a) Does Power Advisory recommend that the Ontario Energy Board maintain the status quo of the current design including a low ETS rate? Please explain fully.

b) Please provide an upper bound on what Power Advisory would consider a low ETS rate.

Response:

a) Yes. As discussed in Power Advisory's evidence, the current market design for pricing imports is dynamic, competitive and transparent. There does appear to be any market failure that a regulatory process must address. Given the combination of the ETS, congestion rents and TR Auction revenues – and relying on previous evidence filed as part of this issue – export customers more than cover the cost of operating and maintaining the interties, which is the only infrastructure explicitly used by export market participants.

   Power Advisory also does not agree with either the pole attachment comparison or the "free rider" categorization of export market participants. Exporters do not make long-term investment decisions to export energy from Ontario, as a telecommunications company would when agreeing to a pole attachment. They are also not guaranteed that the internal transmission network is designed and operated to ensure they are able to flow energy out of the province. They have no control over whether the internal constraints will constrict energy flows to the interties, yet bear that risk if exports are curtailed as a result. Export market participants largely rely on spare capacity in the provincial grid, both in terms of transmission and (to a lesser extent) generation, to export energy from Ontario to neighbouring jurisdictions. Ultimately, they work within the constraints of the grid to find an economically efficient outcome for Ontario's energy – moving it to consumers who value it most in other markets, when possible.

b) An ETS rate that results in a negative financial outcome for Ontario ratepayers should be avoided. Power Advisory recognizes that its analysis was done a historical basis and includes a number of high-level assumptions. This was done due to a combination of lack of detailed, publicly available data and a desire to make the analysis transparent. Based on this analysis, it's not clear that increasing the ETS achieves a better outcome for Ontario ratepayers. In fact, it's much more likely to result in a negative outcome. Given the IESO's evidence, which details the benefits that have occurred under the current ETS rate, there is no evidence in this proceeding to suggest that raising the ETS rate is beneficial. It appears that the opposite – lowering the ETS rate to \$0/MWh – increase the benefits that exports provide to Ontario ratepayers. That said, a \$0/MWh ETS rate may not be viewed as appropriate give the lack of congestion on most hours of the year.

PA-LPMA-3

Ref: Power Advisory Evidence, para. 116
If the OEB determines that an ETS rate should be continued, does Power Advisory believe that the rate should be adjusted on a going forward basis based on the same factors that will impact rates under the incentive regulation mechanism proposed by Hydro One?
Response:
Power Advisory was not retained to provide a regulatory opinion on this topic. Power Advisory maintains its position that the current ETS rate provides significant value to Ontario ratepayers, as detailed in the IESO evidence. Raising the ETS rate can reduce those benefits, while lowering it to $0/MWh increases them, as detailed in our report.

PA-LPMA-4

Ref: Power Advisory Evidence, para. 121
Please define "a materially higher transaction cost through an increased ETS rate". In particular, what level of an ETS rate would Power Advisory not consider to be materially higher than the current level of the ETS rate?

Response:
The OEB typically allows for rate mitigation when rates increase by more than 10%. One contemplated ETS rate increase evidenced in this case could total an increase of more than 200%.

INTERROGATORY RESPONSES TO NAREN PATTANI

PA-PATTANI-1

Ref.: Figure 7 on Page 27 of Power Advisory Report; Table 1 on Page 10 of the Power Advisory Report

Context: The illustrative Figure 7 on Page 27 of the Power Advisory Report explains how the Market Clearing Price (MCP) in Ontario is determined using economic merit orders (generator offer prices).

Questions:

a) Based on how MCP is determined, please confirm that if the total demand in the Ontario system were to be higher due to exports (for example, due to 2,000 MW of exports in any hour), the MCP, and therefore the Hourly Ontario Electricity Price (HOEP), would directionally be higher for the consumers in Ontario in that hour? (Please note that, this question is not meant at all to suggest that exports should be discouraged; it is simply intended to aid in understanding the impact of exports on the MCP).

b) Please explain why such an impact (of higher HOEP due to Exports) was not assessed, nor noted, in the Power Advisory Report, for example in Table 1 on Page 10 which summarizes the Financial Impact of Increase and Decrease to the ETS Rate?

Response:

a) To be clear, export schedules are determined in PD-1 (one hour prior to real-time). Once an export is "economic" in PD-1, its bid is then moved to $2,000/MWh (the ceiling price in the wholesale market) in real-time to ensure that it flows according to its PD-1 schedule. If 2,000 MW of exports were added to the demand curve, it would result in moving higher up the supply stack and higher prices. But exporters are price-sensitive market participants. Power Advisory struggles to envision a scenario where 2,000 MW of exports are added at a price where all of them would simultaneously be scheduled.

b) Given the fixed cost nature of Ontario's electricity grid, all non-Industrial Conservation Initiative (ICI) customers would largely be unimpacted by a marginally higher HOEP as a result of increased exports. And given that most exports occur when HOEP is set at the marginal cost of hydro and zero marginal cost resources, we don't view a situation where exports materially increase HOEP beyond $15/MWh as reasonable.

PA-PATTANI-2

Ref.: Quantitative Analysis in the Power Advisory Report, summarized by Table 1 on Page 10 of the Power Advisory Report.
IESO's Planning Outlook, December 2021.

Context: The quantitative analysis covered by the Power Advisory Report appears to be based on historical data from the years 2018 to 2020 (as stated in para. 23 on Page 10). The IESO's Planning Outlook, December 2021, indicates on Page 5 that there is "potential for considerable change through the 2020s and early 2030s due to the combined effect of nuclear retirements, ongoing nuclear refurbishment outages, and expiring supply contracts and commitments" and that "with the pandemic recovery well underway, the IESO's forecasts show steady average growth (in demand) of about 1.7 per cent a year". It also indicates on Page 6 that "potential energy shortfalls are forecast to begin in 2026 and grow substantially ...".

Questions:

(a) Please explain why the data from the IESO's Planning Outlook was not used to forecast the Financial Impact reported on Table 1 on Page 10?

(b) While it is unrealistic, at this stage, to request that Power Advisory recalculate the numbers to update Table 1 based on the more recent forecast of resource data, please provide a commentary about the directional trend (upwards or downwards) of numbers on Table 1 with the forecast changes in generation resources specifically as per the IESO's Planning Outlook, December 2021.

(c) Please comment on whether the extent and periods of congestion on interties during periods of exports from Ontario are likely to increase or decrease due to the changes specifically anticipated in IESO's Planning Outlook, December 2021.

Response :

(a) Power Advisory purposefully avoided undertaking an analysis based on forecasting. The reason for avoiding a forecast-based analysis is that it would focus the OEB and other parties on the assumptions used as part of the forecast, rather than understanding the impact of a higher ETS rate, which is what we were retained (and accepted by the OEB) to analyze

(b) Reduced amounts of SBG or SBG-like conditions will likely reduce the volume of exports, congestion rents and TR auction revenues. Nonetheless, as described in previous answers, the IESO is currently launching one of its largest procurement programs in the history of Ontario. The implications of that procurement remain unknown. Secondly, a number of neighbouring jurisdictions are facing their own capacity concerns, which may result in an offsetting increase in exports (compared to the decrease expected from reduced SBG). Not in SEC-11, significant congestion rents occurred in hours where HOEP was materially higher – highlighting that congestion can occur as a result of conditions in neighbouring markets, not just SBG in Ontario.

(c) See previous answer.

PA-PATTANI-3

Ref.: - Para 31 on Page 12, and Para 47 on Page 16, of Power Advisory Report
- IESO Document: Ontario Resource and Transmission Assessment Criteria – Issue 5; Effective Date August 2007.

Context: The narrative that Hydro One and IESO do not consider, nor factor, exports into planning is incomplete without clarification, and it needs closer examination. No doubt, Hydro One and IESO do not plan new explicit interconnections to increase existing export capability. However, transmission planners must continue to consider the maintenance of existing intertie capability, including for exports. This consideration is made both for refurbishments at interties and for new capacity planning for internal transmission that feeds intertie points:

(1) Hydro One does indeed spend OM&A funds and, when necessary, capital funds to maintain and replace existing interconnection facilities as well as the internal transmission upstream of interconnections to ensure that the existing export capability is not compromised.

(2) In planning internal transmission system upgrades, Hydro One does include the need to ***maintain*** existing export capacity downstream from the area where local area transmission reinforcements are planned. Indeed, the IESO Document "Ontario Resource and Transmission Assessment Criteria" (ORTAC), which is used by the planners to ***plan internal transmission***, states in Section 3.2 titled "Exports and Imports" that:

> *"All exports and imports should be taken into account to achieve the conditions of section 3.1. The pre-contingency level of the transfer selected should be based on the existing and projected interconnection capability. Combinations of maximum transactions coincident with high internal power flows should be considered in order to stress the import interface and to ensure studies evaluate the full range of power flow scenarios."*

Questions:

(a) Please clarify the notion that IESO and Hydro One do not plan based on providing for Exports (as stated in the Power Advisory report at the location referenced above) by addressing the fact that Hydro One does indeed fund repairs and maintenance of existing interties and internal transmission facilities feeding the interties in order to maintain existing export capability. If it is believed that such funding is not expended, please provide published evidence, or a statement from Hydro One, that Hydro One does not spend any funds to maintain the reliability of existing export capability.

(b) To back up the opinion stated in the Power Advisory report (see reference above) that IESO and Hydro One do not plan based on providing for Exports, please provide evidence, in the form of published material or criteria (such as updated ORTAC) or by a statement from Hydro One, that the need for maintaining (reliable continuance of) existing export capability is not considered in planning internal transmission reinforcements upstream from the interties.

Response:

(a) The IESO explicitly stated that it does not plan the Ontario electricity system to account for exports. Secondly, based on the Elenchus evidence filed in 2014, the current ETS charge of $1.85/MWh is enough to cover the cost of operating and maintaining the interties. If Hydro One views the cost of operating and maintaining the interties as higher than that amount, it can submit that information to the OEB and interested parties.

(b) Power Advisory was relying on the IESO's evidence that stated this explicitly. Secondly, Hydro One has not disputed this claim in previous hearings on this issue. Power Advisory would welcome comments from Hydro One to the contrary. From the IESO's evidence: "The IESO undertakes reliability assessments to ensure the system meets the needs of domestic consumers. Ontario's interties provide reliability benefits (e.g., supply and demand balancing, frequency and regulation control, and other emergency measures), and the IESO plans the system, in accordance with established planning standards, to ensure export capability is sufficient to maintain system reliability and operability. ***However, the needs and activities of competitive exporters (e.g., volume and direction of transactions) are not considered when planning the transmission system, and so are not a primary driver of investment." (emphasis added)***

PA-PATTANI-4

Ref.: Section 4.9 of Power Advisory Report, including comments regarding reduction of ETS Rate to $0/MWh.

HONI Response to OEB Staff Interrogatory Response: Table 3 of Excel File HONI_I-01-01-20220513 (Curtailed Exports Data)
HONI Response to OEB Staff Interrogatory: Attachment File HONI_I-05-24-03_20220513.xlsm: Tab 01 (for Revenue Requirement) and Tab 18 (for Demand Data).

Context: Based on Tab 01 of HONI file HONI _I-05-24- 03_20220513.xlsm, the Network Revenue Requirement for the subject year is $1,800,412,703 and Tab 18 indicates the domestic energy forecast for the corresponding year is 132,225,424 MWhr. Therefore, the *average, effective* Transmission Network charge to be paid by a domestic customer is approximately $ 13.6 per MWhr if the ETS Rate were zero. (Please note that this figure of $ 13.6 per MWhr, calculated based on domestic energy consumption, is provided for context and order-of-magnitude comparison, although it is understood that transmission charges are not collected on an energy basis from domestic transmission customers of IESO. Further, this context is not meant to imply that an ETS Rate of $ 13.6 per MWhr is appropriate).
Based on Table 3 of Excel File HONI I-01-01-20220513(which shows hours when Exports were congested at least on one interface), there was no congestion on any Export interties during anywhere between 65% and 83% of the hours in the years between 2016 and 2021. Thus, Intertie Congestion Pricing (ICP) Charge was not paid by any exports during these periods.

Question:

From an economist's perspective, what is your opinion about the notion that, for a capital-intensive infrastructure for which domestic customers pay effective, average service charges of the order of $13.6 per MWhr, majority of exports and wheel through transactions should be offered the use of that same infrastructure for free during periods when the transmission infrastructure is not fully utilized (if the ETS Rate were to be zero).

Response:

We agree that this could be viewed as problematic by some parties. As discussed in a previous response, rate-setting can include a number of considerations – particularly "fairness". If the OEB or other parties agree that a $0/MWh rate is not fair in hours when the intertie is uncongested they could decide to keep the current rate. That said, in totality, export customers pay significantly more than $1.85/MWh to export energy from Ontario when congested hours are considered.

PA-PATTANI-5

Ref.: Section 4.9 of Power Advisory Report, including comments regarding reduction of ETS Rate to $0/MWh.

HONI Response to OEB Staff Interrogatory Response: Table 3 of Excel File HONI_I_01-01-20220513 (Curtailed Exports Data)

Context: As summarized in the context for Interrogatory #4, the average, effective Transmission Network charge to be paid by a domestic customer is approximately $ 13.6 per MWhr, if the ETS Rate were to be zero.; and for most of the time in a year, Exports do not pay ICP charge. (Please note that this figure of $ 13.6 per MWhr, calculated based on domestic energy consumption, is provided for context and order-of-magnitude comparison, although it is understood that transmission charges are not collected on an energy basis from domestic *EB-2021-0243 (Phase 1) Interrogatories for APPrO* transmission customers of IESO. Further, this context is ***not*** meant to imply that an ETS Rate of $ 13.6 per MWhr is appropriate).

Questions:

Assuming there is no transmission congestion, which historically has been the case more often than not during the year (refer to above-mentioned HONI Response about Curtailed Exports Data), then, from an economist's perspective, what is your opinion about fairness, or otherwise, in the context of "free riding" in the following two scenarios, if the Export Transmission Service (ETS) Rate were set to zero in Ontario and at the same time:

(a) While a Wheel Through Transaction from Quebec to Michigan (using Ontario's transmission system along over a thousand kilometres) would not have to pay any transmission charge, a domestic industrial customer located in Niagara Falls, Ontario, in the vicinity of Ontario's major hydraulic generation facility would still have to pay an *effective charge, on average*, of $ 13.6 per MWhr in transmission service charges?

(b) While a Wheel Through Transaction from Quebec to Michigan would not have to pay any Export Tariff in Ontario, a Wheel Through Transaction from an Ontario generator to New England would pay still pay full Export Tariff in Quebec?

Response:

(a) See our previous response (PA-Pattani-4).

(b) Power Advisory was not retained to comment on the Quebec or ISO-NE markets.

RESPONSE TO INTERROGATORIES FROM AMPCO

PA-AMPCO-1

Power Advisory uses the increase/decrease in congestion rents as a part of the proxy for benefit to loads via reduced system costs.

a) Please provide the value of the payments made from the account to TR rights holders.

b) Please discuss the impact on the benefit calculation if the TR payouts to rights holders/TRA Surplus is factored into the analysis.

Response:

a) Power Advisory declines to provide the information, as whatever is publicly available is on the IESO website.

b) As noted in a previous response, TR holders are made financially "whole" for congestion costs. In a perfectly efficient market, a TR holder would pay no more for a TR than it would offset in congestion. For example (and at a very high level), if $1 million TRs were sold and $1 million of congestion costs were avoided, Ontario ratepayers would receive $1 million from the TRCA. As the Market Surveillance Panel discussed in multiple reports, the IESO for years oversold TRs compared to real-time physical capabilities of the interties. As a result, congestion rent shortfalls were being covered by distributing TR Auction revenues. The IESO has addressed this issue (based on Power Advisory's knowledge). See the MSP's November 2011 – April 2012 and November 2015 – April 2016 reports.

PA-AMPCO-2

Please provide an opinion as to whether and how the implementation of Market Renewal would change Power Advisory's findings.

Response:

MRP is expected to result in both more efficient commitment of thermal units (ERUC) as well as the introduction of Locational Marginal Prices (LMPs). All else being equal, more efficient commitment should result in less over-commitment. For example, the MSP's May 2015 – October 2016 Monitoring Report found that just 1% of RT-GCG commitments were required to satisfy domestic demand. The result would be overcommitment and exporting of energy from facilities that are fully recovering their fixed start-up costs from Ontario ratepayers. To the extent that MRP will address this overcommitment, the need to export energy from over-commitment resources will decline. LMPs will – all else being equal – ensure that investment occurs in parts of the grid where it is most needed. In doing so, it should reduce curtailment or unnecessary exports.

PA-AMPCO-3

Please discuss the view of Power Advisory on Surplus Baseload Generation (SBG) in the future.

Response:

Power Advisory expects SBG to be less severe than it has been over the last decade, which has been an unprecedented period of oversupply in Ontario. That said, the IESO (and potentially the provincial government) are on the cusp of one of the largest procurement programs in the history of the province. The impact of that procurement – both in the amount of MWs procured, as well as what type (i.e. fuel type) of MW – is very much unknown. Given the recent policy calling for a moratorium on new gas-fired generation, it is very likely that a significant amount of MWs will come from intermittent, zero marginal cost resources. Additionally, exports can act as a release valve during unexpected economic downturns and subsequent decline in provincial energy demand – as occurred both in the 2008/09 financial crisis and 2020 COVID-19 pandemic.

RESPONSE TO INTERROGATORIES FROM HYDRO ONE (HONI)

PA-HONI-1

Ref: OEB Procedural Order No. 1 from Hydro One's Joint Transmission and Distribution Rate Application (EB-2021-0110), issued September 17, 2021 ("JRAP PO#1").

Joint submission on ETS rates Hydro One and the IESO in the current proceeding (EB-2021-0243), filed October 14, 2021 (the "Joint Submission").

Power Advisory, Expert Report for the market impacts of changes to the ETS Rate, prepared on behalf of APPrO, filed May 27, 2022 (the "Power Advisory Report").

Preamble:

JRAP PO#1 states, at p. 4 (emphasis added):

> The OEB is of the view that it is also appropriate to deal with the Export Transmission Service (ETS) rate issue as part of the separate, generic UTR proceeding. Hydro One filed evidence on the ETS rate in the current application. In response to OEB direction, Hydro One's ETS evidence includes a cost allocation study, an updated jurisdictional review, and a commentary on market implications of the ETS prepared by the IESO.
>
> Hydro One's application does not include a specific proposal for setting the ETS — although there are a number of cost allocation options identified in the evidence, Hydro One has assumed no change to the current ETS rate of $1.85/MWh in its application.
>
> Similarly, the IESO's commentary discusses the implications of an increased ETS rate for the Ontario market and states that any increase in the ETS rate will reduce the value of interties, leading to less system flexibility and higher costs for Ontario consumers, but it also does not recommend a specific ETS rate for consideration by the OEB.
>
> The evidence filed by Hydro One and the IESO will no doubt be helpful in considering the appropriate ETS rate, however, the OEB has determined that it would be assisted by further clarity from Hydro One and the IESO as to their view of what ETS rate should be adopted.

The Joint Submission states, at pp. 7-8:

> In its Decision on Hydro One's 2020 to 2022 transmission rate application (EB-2019-0082), the OEB "determined that the use of shared network facilities by exporters needs to be considered in setting the ETS rates". The OEB directed Hydro One to provide an ETS study using a cost allocation methodology that includes the allocation of shared network costs to exporters in its next transmission rebasing application.
>
> In addition, the OEB stated that it would be assisted by an updated jurisdictional review that provides the ETS rates in other jurisdictions, the rationale behind those rates and market implications. Recognizing that the operation of the electricity market is the

> responsibility of the IESO rather than Hydro One, the OEB indicated its expectation that Hydro One discuss the approach to the jurisdictional review with the IESO and OEB staff to determine the best approach to complete the review before Hydro One's next transmission rebasing.

The Joint Submission states, at pp. 11-12 (emphasis added):

> Hydro One recognizes that the current ETS Rate was established through an approved settlement proposal and is therefore not entirely cost-based, and that the level of the ETS Rate impacts both transmission rates for electricity customers in Ontario and costs for exporters. Hydro One also understands from the IESO's comments filed in EB-2021-0110 that changes in the ETS Rate can impact the volume of export transactions in the Ontario electricity market, which can impact the economic efficiency of the market. <u>Given these considerations, and the fact that changes in the approved ETS Rate would have a neutral impact on Hydro One's overall transmission revenues as described above, Hydro One does not make any recommendations on a specific ETS Rate.</u> While Hydro One desires the outcome that is best for its customers, it is not in a position to determine what ETS Rate, if any, would ultimately result in the best overall outcome for its customers. As such, having regard to the purposes of the IESO under the Electricity Act and of the OEB under the Ontario Energy Board Act, Hydro One defers to the IESO's expertise and responsibility to advise on the potential impacts of changes to the ETS Rate and the recommended ETS Rate from a market operations perspective, and to the OEB's expertise and responsibility with respect to the balancing of the various competing interests in setting the ETS Rate. Of course, Hydro One has endeavored, and will continue, to support the OEB's decision-making by providing the necessary evidence regarding a cost-based rate.

The Power Advisory Report states, at the paragraphs indicated below (emphasis added):

> Section 4.7 (of the report) describes Power Advisory's analysis on the financial impact of raising the ETS rate by from $1.85/MWh to $6.54/MWh, <u>as is being proposed in this proceeding</u>. (Paragraph 9)
>
> <u>Hydro One's joint transmission and distribution application proposes increasing in the ETS rate from its current level of $1.85/MWh to $6.54/MWh</u> (on an adjusted basis). (Paragraph 17)
>
> <u>The methodology proposed in this proceeding</u> relies on a traditional cost allocation methodology to justify a near four-fold increase in the ETS rate ... The <u>proposed methodology</u> adopts the policy of OEB's generic pole attachment proceeding as part of its justification . . . There is very limited discussion in the <u>proposed methodology</u> on whether a lower ETS rate — which supports a market-based approach to collecting export revenues through congestion rents— is more appropriate than the regulated approach being <u>proposed as part of this proceeding</u>. (Paragraph 31)
>
> At a high level, Power Advisory does not accept the cost allocation methodology <u>proposed in this proceeding</u>. There are many reasons why Power Advisory does not accept the methodology. (Paragraph 46)

Questions:

1. Please explain the basis of Power Advisory's understanding, as indicated by the Power Advisory Report references noted in the preamble, that it was Hydro One's proposal in EB-2021-0110, and that it continues to be Hydro One's proposal in the current generic proceeding, to increase the ETS rate from $1.85/MWh to $6.54/MWh.
2. Having regard to the JRAP PO#1 and the Joint Submission, as referenced in the preamble, please confirm that each of APPrO and Power Advisory understand that Hydro One has not proposed any increase in the ETS rate, or any particular ETS rate, either in the current proceeding or in EB-2021-0110.
3. Please confirm that each of APPrO and Power Advisory understand that the Elenchus cost allocation study, the updated CRA jurisdictional review, and the IESO commentary on market implications of the ETS were each prepared for and filed by Hydro One, first in EB-2021-0110 and subsequently in the current proceeding, solely in response to specific directions from the OEB in EB-2019-0082 to assist the OEB in considering the appropriate ETS rate.

Response:

1. Power Advisory accepts that Hydro One is not proposing an increase, but has filed evidence that supports an increase based on previous directions from the OEB.
2. Agreed.
3. Agreed.

PA-HONI-2

Ref: Power Advisory Report, Section 4.2, Paragraph 42

Preamble:
In Reference 1, Power Advisory states that "The IESO's analysis expects that any increase in revenue from a higher ETS will be fully offset by a decrease in revenue from congestion rents that occur at the intertie (congestion rent is discussed in more detail in a later section of this report). A reduction in congestion rent will reduce disbursements from the Transmission Rights Clearing Account (TRCA), which are used to reduce the overall revenue requirement for Network transmission costs paid by all Ontario ratepayers." (emphasis added)

Question:
Please explain, in detail, how a reduction (or increase) in TRCA disbursement payments will impact the overall Transmission Network revenue requirement that is paid by Ontario transmission customers through Uniform Transmission Rates. Please provide a step-by-step illustrative example.

Response:
Please see response to Board Staff # 8.

That said, Power Advisory welcomes a detailed settlement example by Hydro One on how TRCA disbursements are returned to customers. If Hydro One feels it is necessary and/or prudent to provide the OEB with a detailed settlement example regarding TRCA disbursements, it should do so.

PA-HONI-3

Ref: Power Advisory Report

Preamble:
The Power Advisory Report details that exports are beneficial for Ontario consumers because exports decrease system costs for domestic ratepayers.

Questions:

a) Please indicate whether or not the Power Advisory research considered whether there are instances where the scheduling of export transactions increase:
   i. HOEP; and
   ii. total bill prices paid by Ontario consumers.

b) If there are instances where the scheduling of export transactions increase HOEP and/or total bill prices paid by Ontario consumers, please indicate how these instances are factored into the Power Advisory Report conclusions.

c) Please indicate whether instances where the scheduling of export transactions increase HOEP and/or total bill prices paid by Ontario consumers are expected to increase in frequency or magnitude in the next 5 years.

Response:

a)
   i. It did not. As described previously, exports are price sensitive and are most prevalent when prices are at or below the marginal cost of hydro. As a result, Power Advisory does not expect exports to increase HOEP significantly beyond the (low) marginal cost of hydro or zero marginal cost resources.
   ii. Power Advisory did not undertake a total bill analysis.

b) See previous answers.

c) See previous answers.

ATTACHMENT A

Detailed Methodology:

1. The first step was to compile HOEP and PD-1 pricing data from the IESO's website for the 2018-2021 time-period. The data can be found here: http://reports.ieso.ca/public/PriceHOEPPredispOR/
2. The second step was to compile 5-minute Market Clearing Prices (MCP) for the different intertie zones (i.e. the Intertie Zonal Price (IZP)). The data was then cleaned to create an hourly price for each intertie zone. The data can be found here: http://reports.ieso.ca/public/RealtimeMktPriceYear/ The TR Zonal Price report can also be used, although it only comes in XML format: http://reports.ieso.ca/public/TRAPreauctionHZMCPMonthly/PUB_TRAPreauctionHZMCPMonthly_202207_v5.xml
3. In order to calculate the Intertie Congestion Price (ICP), the difference between the intertie price and HOEP was determined for every hour.
4. The import and export flows for each intertie were then compiled. The data can be found here: http://reports.ieso.ca/public/IntertieScheduleFlowYear/
5. To calculate congestion rents, the difference between the IZP and HOEP (which is the same as the ICP) was multiplied by exports on each intertie when the difference was greater than $0/MWh. The amounts were then totalled for the entire time period (2018 – 2021)
6. With the data described in steps 1 – 5, the average and total amount of exports and congestion rents were calculated using a variety of HOEP ranges. For example, in what we refer to as Scenario A – where the ETS is increased from $1.85/MWh to $6.54/MWh – the price ranges are $-0.1-$4.69/MWh and so on up to $10/MWh. We assume that a higher ETS will have a limited impact on exports when prices are greater than $100/MWh. We do a similar analysis for what we refer to as Scenario B – where the ETS is reduced from $1.85/MWh to $0/MWh.
7. Using the data described in Step 6, we total the reduction (for Scenario A) in exports as a result of an $4.69/MWh increase in HOEP up to $100/MWh. As described through the evidence, the increase in HOEP is used as a proxy as an increase for the ETS (i.e., it would be the same to exports if HOEP was $4.69/MWh higher or the ETS was $4.69/MWh higher). We do a similar calculation for Scenario B, but the impact is isolated to prices below $20/MWh, as that accounts for a majority exports and a $1.85/MWh increase is less impactful when HOEP is greater than $20/MWh
8. Wind data was compiled for all wind assets from 2018 – 2021. The difference between actual and forecasted output was calculated for hours when HOEP was $5/MWh or below. The data can be found here: http://reports.ieso.ca/public/GenOutputbyFuelHourly/
9. The wind curtailment cost was calculated as the decline in exports in the $-0.1/MWh - $4.69/MWh range and the next price range. It is assumed that the decline in exports would be curtailed wind supply. Power Advisory assumed the cost of the curtailed supply to 50% of curtailments.
10. The reduced market revenues are calculated as the decrease in exports multiplied by $4.69/MWh.
11. The reduced congestion rents are calculated as the decrease in congestion rents between the different price ranges.

12. Hydro curtailment was calculated as the decline in exports when HOEP \$13-\$15/MWh and \$17-\$19/MWh multiplied by \$14.40, as this was the assumed marginal cost of the units where surplus supply existed.
13. Prices for neighbouring markets were compiled either from S&P or the websites of system operators (NYISO, MISO and PJM).