Information requests following August 23, 2018 TDAG session

Ed de Palezieux (Devon)

For the Bulk charge work:

1. Pool price forecast for next 20 years (base case). Can then compare this to the pool price forecast under various bulk charge cost allocation methodologies.
2. Transmission plan and build over the next 20 years. Dollars of capital in system projects. Key assumptions (especially on how Bulk charges are allocated in creating the plan).
3. Forecasting methodology for load, key assumptions and load forecast. Impact on load forecast if load changes in the current year.
4. Planning process and steps. Impacts of load or gen changes on the system plan.

In regard to the capacity cost allocation:

5. RAM model understanding in detail
6. List of the RAM model output by EEA events in all model runs by hour
7. Impact of moving 100 MW out of each EEA event hour

Hao Liu (AltaLink, TFO)

TFO group proposes that the AESO cover the following topics and questions, among others, in its presentation to the Advisory Group (AG) regarding the AESO's transmission planning process and the AESO long-term transmission plan (LTP). The overall objectives of the proposed list are: (1) to ensure that the AG members have shared understanding on the AESO's planning approach and criteria; (2) to gain an understanding of the AESO's latest LTP, particularly the regional and bulk system projects and their key drivers; and (3) to clarify, to what extent the bulk system projects identified in LTP are driven by system coincident peak.

1. An overview of AESO planning approach/criteria, including specific obligations/requirement under Transmission Regulation regarding transmission planning
2. What's the definition of "bulk system" and "regional system" projects? Are there any differences with respect to the planning criteria, approach, assumptions, and process between the two types of system projects?
3. An overview of the latest AESO LTP, including the drivers for each of the regional and bulk system projects identified in the LTP both in near- and long-terms as well as estimate project cost for each? How does the LTP relate to specific project NIDs?
4. Which regional and bulk system projects in the LTP are driven by generation (renewable and thermal) or interties? If the project need is split between different drivers, provide the approximate split in $s associated with load, generation and interties?
5. Which regional and bulk system projects are driven by load and specifically the coincident peak?
6. If future coincident peak load is reduced by 10%, which regional and bulk system projects identified in the AESO LTP will be deferred?
7. If future coincident peak load is increased by 10%, which regional and bulk system projects identified in the AESO LTP will be advanced?
8. An overview of TRP model, including a breakdown of regional and bulk project cost at project level
9. An estimate of cost impact associated with the bulk system projects included in the LTP and TRP model.

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Raj Retnanandan (CCA)

Issue 1: Netting of Loads

1. Should the determination in ID2118-19T that STS be based on the sum of the individual feeder flows into the bus, while DTS be based on the coincident sum of the feeder flows out of the bus, be applied to transmission connected industrial loads that i) are part of an industrial system and ii) for others; if there are any legislative impediments to changing the status quo for transmission connected customers, please identify them
2. If the determination in ID2118-19T that STS be based on the sum of the individual feeder flows into the bus, while DTS be based on the coincident sum of the feeder flows out of the bus were applied to transmission connected industrial loads what impact would this have on the AESO's overall billing determinants?
3. Would an approach involving billing based on gross loads help stem the tide of load defections?
4. The determination in ID2118-19T means that STS would be based on the sum of the individual feeder flows into the bus, while DTS would be based on the coincident sum of the feeder flows out of the bus. If this determination were not applied to transmission connected industrial loads, to the extent such customers participate in the capacity market, the generation side of such loads would receive capacity payments while the capacity costs would be allocated to net load only. Could this result in double credit for the netted out load?

Issue 2: Locational Information/Price Signals

5. To what extent is the AESO able to provide locational price signals under current legislation. If changes are required to provide effective locational signals how should the legislation be changed?
6. As part of the information on planning of the system please identify those locations where deployment of resources such as storage could help enhance flexibility and/ or cost efficiency of the system including locations where expanded ATC through addition of storage, may facilitate increased import capability.

Vittoria Bellissimo (IPCAA)

With a consistent data set, participants could analyze potential cost allocation options. The data set would include data for the past 5 years from 2012 through 2017, including:

1. Date
2. Hour
3. AIES demand
4. DTS demand
5. Supply cushion
6. Supply cushion including available ATC
7. Pool price
8. Generation by fuel type including renewables
9. Hourly exports
10. If possible SD1, SD2 and BR3, 4 and 5 hourly output to allow the data to be normalized.

To better understand the implications and efficiencies created via various cost allocation options, it would help if the AESO could also break out the DTS hourly data by components:

11. Demand on the bulk system, with interval meters
12. Demand on the distribution system with interval meters
13. Demand on the distribution system without interval meters

Chris Best (Energy Storage)

There was a request at the August 23 meeting to identify topics or experts to get the group more background and understanding. The only expertise or background I can think of now that I would like is in the area of transmission planning and development, how the system is planned at a high level and more specifically how the Tariff rates, Coincident Peak, Load Profiles, Forecasts and Contract Capacities are utilized or employed in transmission design. Also the process and timing for flowing the design into applications, approvals, facility construction, energization, etc. would be helpful.

Nola Ruzycki (UCA)

The Office of the Utilities Consumer Advocate ("UCA") considers the proposed work plan to be achievable. The UCA hopes that the AESO will remain flexible in order to modify specific tasks as additional cost and planning information becomes available and the Advisory Group moves forward to differentiate between important and insignificant items. It is possible that the timeline for the consultation could be shortened if such flexibility is built into modifying specific tasks, even considering additional items that may prove necessary, or may improve the final recommendations.

The UCA supports the revisions made to the proposed Terms of Reference and believes that it would be beneficial to hold a preliminary session with the AESO's senior system planning engineers to better understand transmission constraints, planning concerns and cost causation relationships early in the process.

Information requests from prior consultation (March- May 2018)

#	Request Summary
1	MW of bypass during coincident peak Summarized by BTF generation, load shedding and other
2	List of projects in 2020-2025 period that could be avoided or deferred through a reduction in the coincident peak Annual capital spend from 2017 LTP for 2018 - 2037
3a	Load analysis by major bulk system lines based on recent historical data Probability of highest 5 hours for each line (planning system) occurring at the same time as the system coincident peak hour, by month (include summary statistics)
3b	Load analysis by major bulk system lines based on recent historical data Based on #3 above, calculate the probability of the peak hours of all lines occurring at the same time as the system coincident peak hour, by month
4	Simulated analysis of go forward system with increase in frequency of cycling and increasing NDV
5	Provide an estimate of the probability of bulk system line peaks occurring at the same time as the 12 CP hours
6a	For cost allocation purposes redefine "bulk" and "regional" system so that: the bulk system comprises HVDC and AC lines operating above 240 kV only

#	Request Summary
6b	For cost allocation purposes redefine "bulk" and "regional" system so that: Regional system AC lines operating up to and including 240kV
6c	For cost allocation purposes redefine "bulk" and "regional" system so that: Provide the resulting cost allocaiton and tariff change distributions by customer class
7a	Modify the existing 12 CP allocators So that the allocations for each of the 12 months are based on the mean of the 12 highest hourly peak demands within that month
7b	Modify the existing 12 CP allocators Provide the resulting cost allocation and tariff change distributions by customer class
8	For cost allocation purposes redefine "bulk" and "regional" system so that the bulk system comprises HVDC and AC lines operating above 240 kV only and modify the existing 12 CP allocators Provide the resulting cost allocation and tariff change distributions by customer class
9	For cost allocation purposes redefine "bulk" and "regional" system so that the regional system AC lines operating up to and including 240kV and modify the existing 12 CP allocators Provide the resulting cost allocation and tariff change distributions by customer class
10	Monitor 12CP demand response. ADC/DUC/IPCAA have stated is on the order of 300-400 MW
11	Uneconomic bypass analysis
12a	Explain the relationship between "Total On-site Generation, BTF Energy and System Load at AIL Peak" 2017LTO Tables in 2017-LTO-date-file.xlsx
12b	If on-site generation at net-load customers is not included within the refereced table, please provide a comparbly annual forecast summary that quantifies this generaiton during AIL peak from 2017 to 2037
12c	What types of generation technologies are included within on-site generation and BTF energy? Are all generation sources (e.g. distribution connected generation including solar and small gas-fired generation units) counted towards these categories or is on-site generation limited to controllable power (e.g. gas combustion turbines)? Is there a minimum or maximum nameplate capacity necessary for inclusion in the forecasts for on-site generation? Is cogeneration considered to be on-site generation? Is load shedding considered to be on-site generation? If any generation technologies are excluded from the definition of on-site generation, please explain why they are excluded.

#	Request Summary
12d	For any technologies such as load shedding that may not be included in "On-site Generation", please provide an estimate of the MW generation of these resources during the AIL peak.
12e	Please confirm that the forecasts for "On-site Generation" and "BTF Energy" do not include planned BTF facilities announced in AESO's monthly project lists. For example, the March 2018 project list1 includes a multitude of new projects in the "BTF" category with a total capacity of over 2000 MW, but the average annual growth in BTF energy at AIL peak is 23 MW per year from 2017 to 2037 according to the LTO.
12f	If the 2017 LTO forecast for on-site generation and BTF energy is based on a list of planned or announced BTF facilities, please provide this list and the corresponding data for expected generation and load at these facilities. If the BTF Energy forecast is not calculated using expectations for new BTF facilities that have been announced, please provide the methodology used to produce this forecast and the forecasted levels (energy produced and installed capacity) of behind the fence generation and distributed connected generation through to the year 2030.
12g	Is the impact of the level of the DTS coincident metered demand charge a factor in forecasted BTF energy? If yes, how is this impact incorporated into the forecast? If not, does the AESO think it is reasonable and meaningful to incorporate this effect into the BTF forecast?
13a	Please provide a table of total installed nameplate capacity (MW) of on-site generation and distributed generation by technology type, by year, for the years 2006 to 2017.
13b	Please provide a table of total gross system load, by hour, for the years 2006 to 2017. Within this table, Please identify the hour of coincident monthly peak for each month.
13c	Please provide a table of total on-site generation and distributed generation, by hour, for the years 2006 to 2017. If it is less cumbersome to provide disaggregated facility-level data, please do so.
14a	Please provide an updated Appendix J with the latest data on the forecasted costs of future transmission projects included in the AESO 2017 Long-Term Transmission Plan and the latest forecasted billing determinants.
15a	Is the AESO transmission planning criteria and methodology posted publicly on the AESO website? If not, would the AESO provide a document describing AESO transmission planning criteria and methodology employed when developing transmission system plans (e.g. the planning criteria used for the 2017 Long-Term Transmission Plan)?
15b	Please identify the primary driver of need for all AESO system project needs identification applications from 2006 to 2017.

#	Request Summary
15c	How is the $1 billion from page 54 of the 2017 Long-Term Transmission Plan disaggregated among the 15 projects it is based on.
15d	Which, if any, of these 15 projects could be deferred or eliminated due to a reduction in the coincident peak?
15e	For each of the 14 projects that are listed on page 70 of the Long-Term Transmission Plan, what is projected estimated cost by project?
15f	Which of these 14 projects listed on page 70 could be deferred or eliminated due to a reduction in the coincident peak?
15g	Please confirm the projects driven by generation investment will proceed regardless, whether or not behind the fence generation results in lower coincident system peak levels. If projects driven by generation investment are dependent upon coincident peak levels, please explain how.
15h	For projects identified on page 70 with a driver as Renewables Integration, would lower load levels at coincident system peak have any impact on those transmission costs?
15i	For projects identified as Load/Transfer-in, would lower load levels at coincident system peak have any impact on those transmission costs?
16a	Please provide an updated TRIP model that reflects the requested re-functionalization of the 240 kV assets proposed by the UCA. This update should reflect all changes to aggregate billing determinants, all changes to cost functionalization, all changes to cost classification, and all changes to all rate components of the DTS tariff including bulk system coincident metered demand, bulk system coincident metered energy, regional system billing capacity, and regional system metered energy.
17	A simple test of any proposed tariff is to calculate DTS charges for a hypothetical customer with a finite capability to produce MWhs of behind-the-fence generation. For two scenarios of otherwise equal MWhs of generation, the lower net load factor customer should have the lower DTS invoice. If not, the DTS is rewarding inefficient configurations of behind-the-fence generation that will lead to a poorer utilization of wires capacity in the future.
18a	Please identify and explain any potential cost reductions in the bulk transmission system (or any elements thereof) as a result of POD (Point of Delivery) load reductions made during the 12 hours coincident with monthly peak aggregate generation without making any reductions to the NCP (Non-Coincident Peak) loads at the same POD.
18b	Please identify and explain any potential cost reductions in the bulk transmission system (or any elements thereof) as a result of reductions of NCP load at any POD.

#	**Request Summary**
18c	Please identify and explain any potential cost reductions in regional transmission systems (or any elements thereof) as a result of POD load reductions made during 12 hours coincident with peak aggregate generation without making any reductions to the NCP loads at the same POD.
18d	Please identify and explain any potential cost reductions in regional transmission systems (or any elements thereof) as a result of reductions of NCP load at any POD.
18e	Please provide a table indicating the changes to cost allocations that would result from the changed definition of bulk system, and the use of 12 hourly averages to determine each monthly CP as requested in the UCA's March 9th Submissions.
18f	Would the UCA proposed change to bulk system definition referenced in (e) above change any of the responses to questions a) through d) above?
18g	Please identify and explain your understanding of the potential cost reductions (in MW) of aggregate generation capacity that could result from POD load reductions made during the 12 hours coincident with peak aggregate generation but that do not reduce NCP loads at the same POD.
19	In addition, the UCA would be appreciative if the ADC/DUC/IPCAA group could provide some analyses of the bill increases that would be incurred by the recently suggested changes to transmission cost allocation assuming that these would translate into changes in the tariff and/or billing practices. Could ADC/DUC/IPCAA differentiate between bill increases that could result from CP to NCP allocation from the bill increases that would result from a change from the billing of net loads for owners of BTF (Behind the Fence) generation to the billing of gross loads?