ENERGY edits to IESO's draft 2017 LTEP Modules
IESO responses are in green – November 29, 2017
Additional ministry questions in red
IESO responses are in blue to ENERGY's red questions – March 9, 2018
ENERGY responses – March 13, 2018
IESO responses are in orange – March 16, 2018

Module 1: Demand

- By End-Use – Res tab
  - Regarding cell A21, is "Space Heating Room" intended to refer to "Space Heating"? Changed to Space Heating
- We suggest the level of detail included be similar to what was included in the 2013 LTEP modules and the OPO. Currently, Module 1 is missing the following
  - "Residential Intensity" – Consider noting that HH refers to "household". Updated
  - "Comm Demand by Building" – Does "Warehouse Wholesale" refer to "Warehouses and Wholesale" or "Wholesale Warehouses"? Changed to Warehouse

Module 2: Conservation

- Achievable Potential tab
  - It's unclear what the difference between market achievable and unconstrained achievable is. Suggest including a reference to the APS study and addendum in the footnotes so the reader can access further details if needed A link to the APS reports was added. IESO has advised it will post the APS Addendum before the modules are posted (currently not available at links provided). IESO will be posting the APS Addendum shortly.
- CDM Cost Effectiveness Tab

- Could IESO staff please reconfirm the stats for 2016. These are significantly different from those reported in previous years! (LUEC in 2016 is reported at 1.8 cents per kWh, whereas in previous years it has been consistently over 3.5 cents per kWh)) To be confirmed; response forthcoming. OK, please confirm Has been confirmed. 2016 cost effectiveness test results' divergence from previous years is almost solely attributed to the Coupons program. In 2016, the Coupons program saw much higher benefits for roughly the same costs as a result of higher uptake and higher net savings in LED bulbs and lower unit incentives, as compared to previous years.

Module 3: Supply

- In footnotes, please explain the difference between the DR resources listed under the "Installed MW of Existing" tab and the "Installed MW of Directed" tab. For the "installed MW of Directed" tab please clarify through a footnote that the government has not directed a future amount for DR, but rather these are capacity assumptions for the purpose of modelling. DR contracts that expire in the "Installed MW of Existing" and "Installed MW of Directed" are now reallocated as capacity that is expired in the worksheet "Installed MW of Expired" – similar to the treatment of other supply resources. Other worksheets including "Installed MW by Commitment" and "MW at Summer by Commitment" affected by this reallocation were also updated. Thank you for the DR related edits to the supply module. DR capacity has now been moved to expire beyond 2019 (supply module). Given the change, does the DR cost forecast in the cost module (CBDR and DR auction tab and Wholesale Market Service Cost tab) need to be adjusted? The changes to demand response in the supply module only relate to the allocation of category (i.e. "Existing", "Directed", "Expired"), but the total amount remains the same. Therefore, the demand response costs in the Wholesale Market Service Cost and CBDR and DR Auction Costs tab remain the same. No adjustments are required. Also given that there is now a DR footnote in the Wholesale Market Service cost tab (cost module), it would be best to delete the specific tab on CBDR and DR Auction costs in the cost module. The CBDR and DR Auction Cost tab was added because the Ministry of Energy requested it. See the request under Module 5: Cost, bullet 5 (i.e. "In an appropriate tab, please also include costs related to Demand Response"). The footnote in tab Wholesale Market Service Cost was added to clarify where demand response costs are recovered. Feel free to delete at your discretion. CRED would like to keep in the CBDR and DR Auction Cost tab, for transparency to those who monitor DR. Okay with IESO.
- "Installed MW by Fuel" – consider spelling out CBDR in the Notes section. Okay with IESO; Ministry of Energy to spell out the acronym.
- On tabs 3 (installed MW by fuel), 8 (MW at summer by commitment), and 9 (MW at summer by fuel) add a line for "planned flexibility/identified needs" that indicates the gap between identified supply sources and anticipated demand. Indicate the MW expected procurement in the future (e.g. through an ICA). The order in which the worksheets are sequenced does not lend itself to having the "planned flexibility" amounts in the tabs noted by ENERGY. As an alternative, the incremental capacity needs that are required over and above existing resources are indicated once we know what is available and what is our capacity requirement - this is shown in a new worksheet, "Incremental Needs". That incremental capacity need can be acquired through a number of mechanisms. While it appears that the Ministry requested more explicit references to Planned Flexibility, IESO's addition of "Incremental Needs" seems duplicative given that the preceding tab (i.e., "Capacity Above Below Reqt") shows exactly the same

numbers. Suggest removing this “Incremental Needs” tab. Tab deleted.
Installed MW of Directed Tab

- The 50 MW in 2017 and the additional 150 MW in 2019 in the ‘Installed MW Directed’ tab appear to be from the 2017 mFIT procurement target, and the FIT 5 procurement. This raises a potential question of how the IESO is counting the 50 MW 2017 mFIT procurement target as directed until such time as everything is contracted? And, at the time the modules were produced, was FIT 5 un-contracted (i.e. still directed)? If the answer to both of those questions is yes, then the table is fine from an accounting perspective. Correct. microFIT and FIT 5 were still “Directed” at the time LTEP analysis was done so they are shown in the Installed MW of Directed tab.
- However, we may have an interest in accounting for the 50 MW from mFIT and the 150 MW from FIT 5 as ‘committed’ rather than ‘directed’ in order to provide a clear message that there are no further renewables procurements planned. 200 MW of Directed MW from 2017 to 2019 appears confusing considering both of the procurements have been run and are closed. This is an issue related to the timing of reporting. Suggest keeping microFIT and FIT 5 as “Directed”, but indicate that those are the last of the procurements. Agreed that a note is fine. Can the note please be included on the “Installed MW of Directed” tab within the Supply module. Okay with IESO; Ministry of Energy to put in the note.

Module 5: Cost

- For the Transmission Delivery Costs, can you provide the underlying assumptions for both the base and incremental costs? Notes added. Regarding transmission, IESO notes on the Module 5 Transmission Delivery Costs tab that “Base Transmission is based on the Hydro One Revenue Requirement Application EB-2016-0160, plus the revenue requirement of the other transmitters obtained from the 2016 Uniform Transmission Rates” and “Incremental Transmission cost is based the list of transmission projects shown in the Transmission Module 4” however Module 4 notes that “Other regional planning projects were also assumed throughout the planning period” in addition to the specific projects listed. Can you provide the assumptions used for these regional planning projects (i.e. cost profile over the planning period, specific projects, etc.)? Or if these assumptions were from the Hydro One Rate application can we modify the Module 4 notes to say “Other regional planning projects listed in the Hydro One Revenue Requirement Application EB-2016-0160, plus the revenue requirement of the other transmitters obtained from the 2016 Uniform Transmission Rates” to close the loop? The other regional planning cost assumption in note for Module 4 represents a $25M/year figure to reflect generic costs for non-specific/unknown projects; they are not from the Hydro One Rate application. Note that the Transmission Delivery cost tab is updated to state the following, "Incremental Transmission cost is based the list of transmission projects shown in the Transmission Module 4, plus an additional $25M per year in capital investments commencing 2020 to cover other unspecified regional projects."

- For the wholesale market service cost, what is the assumption for the RRRP rate going forward? Did IESO assume some portion of the remote connection project costs will be included in this charge? Yes. In 2017, the Rural/Remote Rate is $0.76/MWh based on an average of the EB-2016-0362 OEB Decision of $0.0021/KWh for 6 months and $0.3/MWh for another 6 months based on the EB-2017-0234 Decision. From 2018 to 2035, the RRRP rate assumed is the EB-2017-0234 rate of $0.3/MWh or 0.03 cents/KWh ($2017 Real) - this rate is held constant in real dollars. Can IESO describe how capital and operating cost assumptions for the Remote Connection Project were applied to determine RRRP amounts? E.G. a description of cost inputs for the project over the period? IESO is not responsible for setting the RRRP, as the RRRP rates assumed as per OEB Decisions. The OEB would be in a better position to describe how the capital and operating costs for the Remote Connection Project were applied to determine the RRRP amounts.
- DRC – DRC is expected to end before April 1, 2018. Why is DRC about the same amount in 2018 ($0.61B) when compared to 2017 ($0.62B)? The expected expiry date of April 1, 2018 was not used; rather it was assumed in the modelling that the DRC is in place for the full calendar year. A note is included in the "Debt Retirement Charge" tab. Flagging IESO's assumption regarding DRC is inconsistent with MOF's public statements. Acknowledged – that is fine with the IESO.
- In an appropriate tab, please also include costs related to Demand Response. Demand Response is recovered through the wholesale market charge. A note was added to the "Wholesale Market Service Cost" tab. CBDR and DR auction costs that are embedded in the wholesale market service costs are indicated in a new tab "CBDR and DR Auction Costs". "CBDR and DR Auction Costs" – Cell A1 should read Capacity-Based Demand Response, not Customer-Based Demand Response. ENERGY can make the change to the Module
- On tabs 1 (cost of electricity service) and 8 (debt retirement charge), why is the DRC expected to be $600M in both 2017 and 2018 despite the charge being removed from bills as of March 31, 2018? The expected expiry date of April 1, 2018 was not used; rather it was assumed in the modelling that the DRC is there for the full calendar year, as noted in the response above. Flagging IESO's assumptions regarding DRC are inconsistent with MoF's public statements. Acknowledged – that is fine with the IESO.

- Don't use "pre-FHP" amounts in tab 10 (global adjustment costs) and tab 11 (residential bill forecast). Fair hydro plan is legislated government policy and should be included in the cost forecasts. Given that IESO did not develop the FHP forecasts we leave that up to the discretion of ENERGY to replace these tabs with information they are more comfortable with, as discussed earlier with ENERGY. For the GA tab, full GA pre-OFHP must be shown since it represents the costs being paid to generators. The full GA pre-OFHP to be depicted in the total system cost line. Row 6 is the forecast total system cost to all consumers. Removed the text ("prior to Ontario Fair Hydro Plan") from the title of the table. For the residential bill tab, as noted by the yellow highlighted rows and blue tab, the residential bill has been replaced by the Ministry. Acknowledged – this is fine with the IESO. Please delete cell A1 as the consensus is to leave this tab as is. ENERGY can make the change to the Module
- Include the 2017 price curve, broken down by line item. ENERGY is to provide clarity on this request, as discussed with ENERGY ESPD staff. In response to IESO's comments in green, ENERGY has updated the module – see yellow highlighted rows and blue tabs. The Ministry has replaced:
    1) Residential bill forecast;
    2) Class A and Class B commodity cost; and
    3) Large industrial indicative cost.

  Acknowledged. A typo is corrected for the Electric Commodity Cost tab for the word Commodity in the notes. A comment for the Ministry of Energy is added to the Large Industrial Price Forecast tab to suggest a way to make the data less confusing. Agree with IESO's suggestions (i.e., rename the "Total" line to "Industrial Rate (including Tx, Reg. Charges and DRC)", eliminate the border line above row 5, and use an empty row to divide rows 4 and 5). ENERGY can make the change to the Module
- Additional ENERGY comment on nuclear costs. In the FAO's report on nuclear refurbishments, released a couple weeks ago, the unit cost of nuclear was calculated differently in order to respect the confidentiality of Bruce Power's contract price. Given the prices in Module 5, one could back out the Bruce contract price by subtracting OPG's regulated rate and production which are available in OEB rate filings. We ask that IESO reconsider its presentation of the unit cost of nuclear. From the FAO report:
- *… in each year, the FAO calculated the production weighted average of the FAO's estimate of the actual OPG nuclear price and the average Bruce Nuclear Price of $80.6/MWh. The FAO is unable to include the actual Bruce Price estimate in the Base Case Nuclear Price trend due to disclosure restrictions under s.13 of the Financial Accountability Officer Act, 2013.* In response to the

Ministry's suggestion[1] provided on March 7, the IESO has rounded all the values to a smaller number of decimals. Should this be deemed unsatisfactory, the IESO requests ENERGY to follow up with a phone call/discussion on how the unit cost of nuclear should be presented. ENERGY's suggested approach (i.e., rounding the values in the spreadsheet) is contingent on IESO's determination of whether such an approach respects the confidential information of IESO and Bruce Power.

- IESO will need to discuss the matter with its own contract management team, as well as Bruce Power, to finalize the Module.
- The IESO is comfortable to publish forecasted total nuclear costs publically. Although Bruce Power's confidential information was used at some point in time as an input to derive the IESO planning assumptions, none of that confidential information can be deduced on a go forward bases, even if public OPG figures are subtracted from the total figures. We arrived at this assessment based on several factors:
    - OPG's nuclear assumptions used in the IESO's forecasts are not the same as those that OPG submitted to the OEB (and which continue to evolve)
    - Bruce Power's assumptions that made it into IESO assumptions are diverging due to various elements, including market changes for fuel costs, escalation differences, operating efficiency sharing, outage performance and several others
    - We performed an exercise to see if we can calculate Bruce Power's expected costs by subtracting OPG's public forecasts in OEB submissions from IESO's forecast. Although the results were directionally similar to what we have in the Bruce financial model, they were not close most of the years.
    - Bruce Power's directional forecast can be derived by estimating total production (i.e. 6300 MW at about 90% capability) times an assumption of future price (based on current public price) and the results would be no better or worse than what can be deduced form the exercise noted above
    - TransCanada, being a public company, publishes enough information to calculate some of the same figures noted above to get the same directional results

[1] On March 7, 2018, the IESO received the following response to the nuclear unit cost question: Alternatively, the IESO could consider rounding the unit cost data for all generation types. The proposed Module 5 spreadsheet includes unit cost data to 10+ decimal points. Greater rounding would reduce the accuracy of any calculation that attempts to back-out the Bruce price from the module (pending confirmation from IESO/Bruce Power on whether this meets disclosure restrictions).