OBSERVATIONS AND COMMENTS RE: MINISRTY OF ENERGY SUBMISSION

(Input from COE, PEMD, OPCD, OFA-MOF)

OVERALL COMMENTS:

- Need to understand the models and the assumptions embedded in them to assess the validity of the estimated impacts/forecasts. It will be important to understand the sensitivity of the models and the financial impacts to the assumptions. Sensitivity analysis would allow the government to make better informed decisions and to develop a risk based outlook to manage potential fluctuations in the cost of these initiatives.

- Given the scale and scope of the initiatives that are being proposed, it is important to note that there will be significant incentives/disincentives being introduced. It will be important to understand how these may impact the behaviour of various key stakeholders going forward and hence the assumptions built into the models and the financial estimates.

- The submission states that the electricity prices are projected to increase above inflation for the foreseeable future. While there are a number of initiatives referenced in the deck to bend the cost curve, it is not clear what the estimated impact of these changes would be. Are these measures projected to limit the increases in the price of electricity at or below inflationary increases? Otherwise, the widening gap will continue to drive need for government action, creating future pressures on the Fiscal Plan.

- With so many proposed changes impacting different consumers, and costs shifting from the rate-base to government funding, it will be important to understand the profile/net impact of the changes on different customer groups and geographies. Need to know the net winners and net losers.

- Energy noted that 2017-18 fiscal impacts were full year, also noted that many initiatives will likely take 3 to 6 months to roll out. Request the Ministry of Energy to refine estimates for 2017-18 fiscal year to reflect the appropriate partial year cost of these initiatives.

GLOBAL ADJUSTMENT (GA) SMOOTHING:

Energy notes the GA is reduced to achieve the initial 25 percent reduction (Total Bill) based on the projected price for the average Toronto Hydro customer. The modelling then assumes GA is removed to achieve the flat 2 percent increase each year per to 2021.

There are three main risks to consider in relation to this initiative:

1. *Accounting Risks and the Impact on the Fiscal Plan*

- The submission assumes that the proposed GA smoothing will receive the favourable accounting treatment; hence the provincial debt would increase, net debt would not change and the fiscal plan would not be impacted (there would be an increase in interest-on-debt and an increase in income from government business enterprises).
  - There are a number of complex issues that need to be addressed and stringent criteria to be met to achieve a satisfactory path forward. Several requirements are high risk.

- No discussion with OAG; in previous Annual Reports, the OAG has raised concerns about the appropriateness of recognizing rate regulated assets and liabilities.

- The structure, term and timing of the financing for GA smoothing are highly dependent on the IESO's forecast of GA costs.
  - For example, decreased market prices of electricity would lead to higher GA costs to ensure payments to generators. While customers traditionally pay both the reduced market price and higher GA to recoup these costs, the entity financing the GA would need to have increased borrowing.
  - Volatility in prices and GA could lead to much variability in the amount borrowed.
  - Cost is also highly dependent on actual interest rates over time.
  - So, f this key assumption re: favourable accounting treatment is incorrect, the impacts would be significant and can vary depending on the market changes. In addition to having a significant fiscal impact, the proposed plan would also introduce significant volatility to the medium- to long-term fiscal plan (as interest rates, energy prices, consumer behaviour changes, etc.).

- Increased borrowing over time would strain the province's ability for continued borrow.
- Annual borrowing could range from $1.6 Bn to $3 Bn with accumulated debt peaking at $38.5B depending on the scenario chosen (based on Feb 22 scenario).
- The current projections use nominal interest rates of 5%. The average interest rate in Canada between 1990 and 2017 was 5.94% (from high of 16% in Feb 1991 to 0.5% in April 2009), which includes the last decade that has experienced historically low interest rates. Given the 30 yr projected time horizon, what would be the impacts and funding requirements be at different:
  - Interest rates; and
  - Scenarios for electricity prices.
- It should be noted, that unlike a mortgage where payments from the outset are used to pay for both interest and principal costs, the financing undertaken for GA smoothing would not pay principal amounts for the near longer term, and interest would be capitalised instead.

2. *Program Design Elements and Implications*

- Energy's earlier drafts were based on the premise that the GA would apply to customers participating in the Regulated Price Plan (RPP). However, given there are eligible customers who have opted out of RPP, the proposal has since been revised to have GA apply to all eligible customers in the Regulated Price Plan regardless of their current participation. If so:
  - What sort of mechanisms will the Ministry of Energy put in place to ensure that those that benefit from this measure can't opt-out in the future when the payments start increasing?
    - If the consumers who benefit from this initiative are allowed to opt-out later as $ higher payments are needed to pay for the deferred GA amount, the government may face a vicious cycle (as more people opt out, the recovery $/% per remaining household increases, which further creates incentives to opt out of the RPP), possibly stranding the balance as unfinanced debt. Is the government assumed to be underwriting this risk? To deal with potential stranded debt?

- The analysis is performed on a "typical" customer. Energy deems this to be a Toronto Hydro customer with 750 kWh monthly consumption, however issues may arise in this assumption:
  - The Delivery Cost component of a hydro bill varies across distributors even at the same monthly consumption amount. However the electricity component of the bill - which is targeted by GA Smoothing proposals - would stay the same as RPP prices are applied province-wide.
  - The proportionate impact of changes targeting the Electricity component of the bill would vary from LDC to LDC.
  - Unlike OREC or the former OCEB program which apply a rebate/benefit on a proportion of the total bill, this GA smoothing proposal would have varying levels of proportionate impact.
  - ENERGY's deck uses Toronto Hydro, a higher cost distributor, as an example. As a result, a 25% impact bill impact from GA smoothing for Toronto Hydro would have a much greater impact for other, lower-cost, distributors, where the electricity component of the bill is larger in proportionate terms.
  - This across the board reduction for GA costs would not targeting those with higher electricity bills, as it would be reducing the electricity component equally on a dollar value basis for all customers.
  - If the objective of this proposal is to provide a 25% reduction to electricity bills across the board, an OREC-type program would be more appropriate to achieving this policy outcome, compared to the disparate reductions provided through a GA smoothing approach.
- Conservation efforts are hampered when across the board reductions in the cost of electricity are imposed. This will diminish price signals and other incentives to reduce consumption.

3. *Legal Risk*

- This proposal subsidizes near-term consumers at the expense of long-term and future consumers.
- Legal advice on the constitutional risk posed by the proposal to defer the current costs to consumers of the global adjustment, to be paid for by consumers in future years, noted a moderately high constitutional risk of resulting in an unconstitutional tax. It creates a refinancing structure which results in future consumers paying disproportionately more of the GA cost and therefore cross-subsidizing near-term consumers.
    - This advice was based on a review of the proposal from February 9, 2017. The Ministry's draft Cabinet submission indicates this risk could be eliminated, either up front or retroactively, by the imposition of a valid tax.

RURAL AND REMOTE RATE PROTECTION PROGRAM (RRRP):

- The goal of the proposal appears to be to remove rate pressures from all residential consumers by shifting costs to government funding (contributing towards the overall, e.g., 25% reduction target) and to enhance benefits.
- Energy characterizes this enhanced relief as an acceleration toward the OEB initiative for LDCs to have fixed distribution delivery rates,
    - The proposal is a subsidization of high cost distribution as the cap is based on the lowest average distribution rate paid by consumers in this group of LDCs.
    - Fixed distribution delivery rates will benefit higher volume users, who will benefit proportionately more than the cost to lower volume users.
    - Will not impact other delivery charges (e.g., transmission).
- Moving existing RRRP costs to government funding base does not provide mitigation beyond the approx. $1.60/month for the typical Ontario household (about 1% of the typical 750 kWh/month customer's bills).
- Energy does not clarify if the cap would increase every year to reflect increasing costs.
- RRRP is not income-tested and may be providing additional benefit to non-vulnerable consumers, in contradiction to the policy goal outlined in Energy's deck.
- Increased fiscal exposure if rates that the OEB attributes to the LDCs over time rise faster than the increase in cap.
- Hydro One R2 customers would be receiving this enhancement on top of existing expanded RRRP savings.
- Overall, the program is likely to create disincentives towards productivity and performance improvements to drive down delivery costs/changes. Furthermore, the proposed approach may create an incentive for LDCs that fall just outside the cut-off to drive up their distribution costs to gain eligibility into the program. (Toronto Hydro is just below the cut-off).

- Slide 21 notes that forecasting the funding requirements associated with the RRRP enhancement is difficult due to year to year variability of distribution costs. Further the footnote on the table suggests that while the costs will decrease through 2023 due to rate making changes, the costs are expected to increase post 2023 due to regular rate increases. It is recommended that the Ministry provide a long term forecast, with risk bands that account for variability of distribution costs, to show the full expected financial impact of this initiative on the fiscal plan.

- The submission notes that the forecasting and costing of the program requires alignment between a large number of parties (LDCs/OEB/IESO/Province). As such, it is likely that financial requirements and uncertainty/volatility will increase over time.

ENHANCE ONTARIO ELECTRICITY SUPPORT PROGRAM AND FUND THROUGH GOVERNMENT FUNDING

- ENERGY assumes reaching 100% participation from years 1 to 4, noting it's an optimistic assumption. Not clear if it remains an application based program (notes Premier's preference to make it an entitlement program versus an application program)

COE

- Given the funding requirements for this initiative almost doubles (from $178M in 2017-18 to $334M in 2020-21), we assume that the Ministry of Energy has built in an increase in take-up rates, as well as the financial impact of the 50% enhancement into their costing estimates.

- Current program take-up rate is 30%. Consideration could be given to focussing efforts on increasing the take-up of the existing program, and seeing the effectiveness of the supports, before benefits are further enhanced.
    - Behavioural Insights Unit (BIU) can help support efforts to increase uptake of the program. Increasing awareness of the program + removing barriers to enrolment/making the enrolment process easier is expected to have a significant impact on the program.
    - This approach would not only lower the fiscal impact in the short-term, but ensure that the effectiveness of the program can be assessed before it is scaled up.

OFA

- Moving existing OESP costs to government funding base does not provide mitigation beyond the approx. $0.83/month for the typical Ontario household (about 0.5% of the typical 750 kWh/month customer's bills).
- Energy policy rationale for moving such programs to the tax base is to contribute to the rate mitigation target and not have social programs cross-subsidised by other ratepayers.
    - Note that when OESP was planned, Energy noted that low income support was provided in other rate-regulated jurisdictions and was found to be justifiable so long as it was part of a

comprehensive regulatory structure and provided some benefits to other ratepayers, which it was found to do.

- TPD has raised the issue that changes to the design of the OESP should be discussed with the Canada Revenue Agency to ensure that it does not become a taxable benefit. When OESP was created, TPD worked with Finance Canada and Energy to ensure that it was not considered a taxable benefit.
  - Federal government may be unwilling or unable to administer OESP due to complexity and the significant restrictions that apply to using federal tax forms.
  - Energy has stated that it has been in discussions with CRA. A status update from Energy should be sought.
- Would provide on-bill benefits.
- Could contemplate phase-in to manage fiscal impact.
- Could look at phasing out existing fiscally-funded programs also targeted to low income or identified groups (e.g., OEPTC, NOEC).
  - These existing programs are not on the bill, so less direct and less visible electricity cost mitigation.
- Phase-out to reflect time to increase application based OESP reaching an increasing portion of eligible households.
- As program eligibility is based on income and household size, it's unclear how on-bill benefits would accrue to those living in rental accommodations where electricity bills are included in rent.
- No fiscal impact estimations provided for the costs to add additional groups for eligibility.

ESTABLISH AN LDC AFFORDABILITY FUND:

- The Ministry is proposing to establish a fund, administered by LDC(s), to extend the existing Low-Income Conservation Program to other electricity customers (customers who are not low income but are in arrears of their payments, may be facing disconnection but do not qualify for the existing low-income programs).

- With the eligibility criteria, delivery models and business case still in development, it may be premature to proceed with the proposal. Having a better understanding of why the target households are in arrears of payment would be key to structuring an effective program.

  - BIU can help with addressing the late payments (like we have done with MOF and late payers)
  - Without a clear understanding of why payments are delayed (or how the payment patterns may be changing), there is the danger of incenting adverse behaviour (delaying payments on purpose to become eligible for grant payments) regardless of the capacity to pay.

Controllership Questions:

- Why is there a need to move $200M out of the CRF by the end of March? What is the ministry's risk assessment of negative AG comment if payments are flowed in advance of need to trust administrator, but before year end?
- Over what period will the funds flow to the ratepayers?
- Is the IESO playing a role in this fund? If so, what is their role?

- The deck notes that there is a fiscal risk if monies used for the fund do not flow before FY year-end 2016/17 and for monies that are sitting in Hydro One at year-end (because of consolidation with province), and a corresponding fiscal pressure in the following years when the funds are flowed from Hydro One (H1) to ratepayers.

IMPLEMENTING ON-RESERVE FIRST NATIONS DELIVERY CREDIT

- Incredibly specific number of customers (21,494), yet such a round and flat estimate of cost @ $13-$20M. Why the broad range? What is included in this model?
- Energy's deck did not explain why these programs should be funded through the tax base.
    - Energy states that the OEB "suggests that the program could be funded by the tax base" but this was likely to be one of many options noted by the OEB rather than prescriptive advice on the matter.

Remove Debt Retirement Charge Early (DRC) for Non-RPP Class B Consumers

OFA

- Energy's fiscal impact estimation for option does not include interest costs borne by deferring DRC payments to 2018-19 fiscal year. Assumes loss of $197M in 2017-18 will lead to a gain of $197 in 2018-19.
- Prior Budget 2016 language referred to the fixed end date of the DRC as "providing certainty to commercial, industrial and other users, and helping them more effectively plan their business and investment decisions". Extending the fixed end date for industrial users would be counter to this previous Budget commitment.
- MOF would need to conduct a detailed analysis for a refined fiscal estimation in all scenarios.

(NOTE: Additional proposal/investigation sought to target the DRC elimination for Class B customers of specific industry classes.)

- Would need to assess Legal and LDC implementation issues.
- <u>Legal.</u> Class A and Class B users are defined in regulations of the *Electricity Act* which would allow reference to such definitions in setting rates or exempting groups of users under the DRC regulation, which can be done through an LGIC regulation. Change in end date would require a legislative amendment.
- <u>LDCs.</u> Unclear of the viability of targeting DRC reduction for particular groups of customers within Class B, due to requirements for local distribution companies to assess the manufacturing or non-manufacturing nature of each Class B customer.
    - May need to be application based, increasing the implementation timing and burden.

    - Would likely require verification and audit provisions.

- May affect choice of Class B manufacturers larger than 1 MW that are eligible for Class A ICI to not opt to be Class A. Could increase complexity of program cost estimates and administration.
- Could be subject to trade issues – TBD.
- The Industrial Conservation Initiative (ICI) and Industrial Electricity Incentive (IEI) programs had eligibility based on industrial sector; however, this proposal to target specific Class B industries, pose additional complexity:
    - ICI participants are a relatively few large users. Many large industrials are directly connected to the transmission grid. Approximately 1,500 customers fall in this category and significant reductions in electricity costs (10%-34%) compelled compliance based on historical numbers.
        - DRC reduction are estimated to provide only a 4% savings, mitigating the desire for eligible participants to participate.
    - The IEI program has only 22 participants, and each one is required to provide a detailed application in order to be selected for the program.
        - Sheer number of applicants would overwhelm LDCs if the Class B DRC benefit is to target a particular group of participants.

    Forecasting the potential fiscal impact of the proposal would be challenging. The impacted consumption would be Class B customers that are non-RPP and non-ICI customers which could be difficult to identify and forecast.

QUESTIONS RE: GA ADJUSTMENT

Questions for IESO and Auditors:

- What is your assessment of risk on both recognizing a regulatory asset and then selling it to OPG Trust? What factors into your assessment? Are you aware of any other entities following public sector accounting standards, presenting regulatory assets on their financial statements?
- Is there anything else that could be done with the proposed structure to reduce the risk?
- What is your assessment of risk of the structure as a whole?
- Based on your understanding of the facts and assumptions, are you expecting to be able to issue a formal accounting opinion on both the ability of IESO to record a regulatory asset and the ability for IESO to sell it to OPG Trust?

Questions for OPG and Auditors:

- What is your assessment of risk with respect to recognizing an intangible asset for the purchase of the regulatory asset from IESO and being able to consolidate OPG Trust with OPG?
- Is there anything else that could be done with the proposed structure to reduce the risk?
- What is your assessment of risk of the structure as a whole?
- What are the most significant risks in being able to maintain the consolidation of OPG Trust with OPG over the duration of the structure?
- Financing – if the OEB or the legislation caps the rate at which financing costs can be passed on to the ratepayers, does that impact the analysis on consolidation of OPGTrust with OPG?
- One of the OPG slides speaks to the need for a provincial guarantee if a change in legislation puts the private debt holders at risk of recovery – what is the cost of this guarantee (e.g. rate differential)? Is this guarantee necessary to obtain any external funding? Are there alternatives to a provincial guarantee?
- What would the admin costs be to manage this structure?
- With the increased debt take on, will OPG (consolidated) be able to maintain its operations and meet its liabilities from revenues received from sources outside of the Province (e.g. the key criteria to remaining a GBE)

Questions for Energy and OPG:

- What is the timeline to complete revised modelling re: the cost of the overall program to the Province (with external financing and an equity injection from the Province to OPG as well as estimate for administrative costs)

Questions for MOF/OFA

- What impact would a provincial guarantee for the 3rd party debt have, if any, on the Province's cost of borrowing?

- Has the OFA had any discussions with OPG re: how and when the equity injection would be provided to OPG – does that timing create any concerns for OFA re: key performance indicators (e.g. impact on IOD?)

Questions for TBS/OPCD

- How does this structure align against the goal of transparency?
- Have any other jurisdictions completed a transaction similar to this?
- What do you believe the AG's reaction will be to this structure?