APPrO
ASSOCIATION OF POWER PRODUCERS OF ONTARIO

APPrO Submission
November 8, 2022 Expedited LT1-RFP and Draft Contract

The Association of Power Producers of Ontario (APPrO) appreciates this opportunity to provide feedback on the draft Expedited Long-Term 1 RFP (E-LT1) and draft contract.

During the course of stakeholdering the draft RFP and contract, there was no clear direction whether new gas would be eligible to participate in upcoming procurements. As such, feedback provided by stakeholders to-date likely did not have a gas perspective when commenting on the draft contract. In light of the recent October 7th Interim Eligibility Report and subsequent Ministerial Directive to procure up to 1,500 MW of additional new natural gas fired generation, APPrO wishes to take this opportunity to provide further feedback on the draft contract. Without these reasonable accommodations to the form of the contract, the IESO's objectives to procure reliable and cost effective supply may be at risk.

APPrO's comments will focus on:
- Term;
- Planned Outages;
- Non-Performance Charges;
- GHG Abatement;
- Capacity Check Test;
- Monthly Average Offered Quantity/Availability.

TERM
Expansions at existing facilities are likely to be among the most de-risked and cost competitive projects eligible for the upcoming RFPs. The IESO had originally contemplated a standalone procurement process for such projects, recognizing the development, construction, and operational differences of Expansions relative to traditional greenfield projects. While the IESO subsequently moved off that idea, opting instead for Expansions to compete against all other projects and technologies in the Expedited and Long-Term RFPs, it has more recently moved back towards technology/circumstance-specific procurements. Doing so has opened up the opportunity for specific procurements to address the needs and characteristics of specific technologies and project types.

APPrO believes this bespoke procurement approach is appropriate for Expansions. While Expansions may be contracted, dispatched, and metered separately from their incumbent generator, there are still critical interdependencies between the existing facility and the Expansion, including: land leases, gas and electricity transmission infrastructure, staff, Balance of Plant costs, etc. When both existing and expanded generators are operational, the facility as a whole benefits from economies of scale and sharing of these costs. In contrast, the shuttering of the existing generator would burden the Expansion with all of these costs, many of which would not decrease as a result of losing the existing generator (for instance, land leases may be for the entire footprint of the combined facility, meaning lease costs would not decrease if the existing facility were shuttered).

In addition, the APO makes clear that the IESO will be relying on existing capacity long after their current contracts are over. Assuming these resources can be re-procured at end of term via the MT-RFP (or Capacity Auction) is a flawed assumption. This has been borne out by the result of the recent MT-RFP, which procured far less capacity than the IESO set out to acquire, with some resources declining to participate in favour of more commercially viable alternatives.

In short, there are operational, cost, and reliability benefits to aligning the economic lives of existing generators and their respective Expansions. Extending the contract term of existing facilities awarded an Expansion is one way to do that. A similar approach has been taken with the Same Technology Upgrade procurement, where existing facilities have the opportunity to extend their contracts out to 2035.

To adopt this approach, the IESO would presumably need to develop a standalone procurement mechanism for Expansions, just as it had originally contemplated. This standalone mechanism would procure capacity through a bundled product (Expansion plus extension of the existing contract), perhaps with minimum Expansion size requirements and/or higher weighting placed on new capacity. Such a procurement design would take time to work out, (suggesting alignment with the LT1 RFP is more realistic), but could unlock significant benefit for suppliers, ratepayers and the IESO.

PLANNED OUTAGES

The Planned Outage Capacity Reduction Factor (POCRF) as proposed in Exhibit E-1 is unduly restrictive (i.e. under no circumstances will POCRF be less than 0.95), especially for natural gas-fired generation which at times requires several weeks of planned outage time to complete major maintenance. Suppliers should not be subject to a deduction to their capacity payment during times of planned maintenance, as is proposed in the current draft contract. The costs to maintain the facility are real costs to the Supplier and will need to be recovered. As such, APPrO recommends that, similar to the MT1 Contract, the POCRF in the E-LT1 contract should be zero during a planned outage.

Furthermore, the IESO 'preferred' outage window is too narrow and will create challenges for Suppliers. The IESO is signaling (through the monthly non-performance factors) that the ideal time for all resources to take planned outages is during the months of April, May, October and November. However, this will create risk for Suppliers of not being granted their planned outage by the IESO as all resources under this contract will be requesting outages during the same time periods. A Supplier should not be penalized through the non-performance charge if it is essentially forced by the IESO to take a planned outage in a month outside of April, May, October or November because the IESO could not support an outage in the preferred month due to grid reliability issues.

NON-PERFORMANCE CHARGE

The construct is onerous in relation to the treatment of Planned Outages and amount of clawback. Further, if the availability of the Facility is less than 75% over a two-year period, it will constitute an Event of Default under Section 10.1(k). Given the clawback feature of the Contract pricing, this Event of Default further adds to the onerous nature of the risk profile prescribed by the MOO. We note also the separate Event of Default in Section 10.1(i), in the event that a Capacity Check Test results in a Capacity Reduction Factor (which reduces the Monthly Payment) of more than 15% - i.e. less than 85% of the Contract Capacity, can be generated by the Facility. As a result, the penalties are duplicative and overlapping, unnecessarily adding to the risk profile of suppliers. This can only result in higher capacity prices.

GHG ABATEMENT PLANS

Section 2.15 addresses consequences of the implementation of a net-zero policy for natural gas-fired generation and expressly takes it outside the scope of Section 13's Discriminatory Action regime. In APPrO's view, the provision as currently drafted is flawed.

First, the premise of the provision and the relief it provides is dependent on:

(i) the Supplier incurring costs as a result of the laws that implement the proposed Clean Electricity Standard,

(ii) the incurring of such costs causing a Material Adverse Effect on the Supplier in order for the Supplier to continue to meet its must-offer condition obligations, and

(iii) Supplier using Commercially Reasonable Efforts to demonstrate that has mitigated or avoided such costs.

If this multi-part test cannot be met or demonstrated to the IESO's satisfaction, then the provision (and the resulting relief) ceases to apply. In the event the provision does apply, the Material Adverse Effect is narrowly defined and thus provides Suppliers with little certainty that a range of circumstances would qualify as MAE. APPrO would support a better defined protection from the impacts of carbon policy. Were net zero legislation to be passed, one approach could allow Suppliers a one-time opportunity to opt for Safe Standby or CES Decommissioning (applicable at time net zero goes into effect), regardless of the requirement to demonstrate Material Adverse Effect and/or Commercially Reasonable Efforts to mitigate costs. This will effectively sort those that face Material Adverse Effect, without the need to define what that constitutes ahead of time, or have Suppliers prove it later. Under such an arrangement, since it is more economic to opt for Safe Standby or CES Decommissioning, those Suppliers that face a Material Adverse Effect, would be incented to do so, while those that do not face a Material Adverse Effect would be incented to continue normal participation in the market. Additionally, the scope of relief afforded has been significantly curtailed to be based on Supplier's costs incurred, not "Supplier's economics".

If the Material Adverse Effect requirement is retained and the IESO accepts a Supplier's CES MAE Notice, the Supplier can choose to mothball the Facility ("Safe Standby") or permanently decommission it ("CES Decommissioning"). Once in Safe Standby, Monthly Payments continue during the remainder of the Term. Although IESO provides that the Availability Non-Performance Change would not apply in such circumstances, the provision is silent with respect to the other factors that operate to reduce Monthly Payments. On a CES Decommissioning, Monthly Payments will continue during the remainder of the Term, except the Fixed Capacity Payment will be reduced to 75%; however, the IESO does not stipulate additionally that any of the deductions to Monthly Payments (including the Availability Non-Performance Charge) would not be applicable. No relief is available with respect to foregone market revenues, or the costs of Safe Standby or CES Decommissioning. Finally, if Safe Standby is chosen, the Facility will need to be operational within one month following the repeal of the applicable net-zero policy (i.e., Clean Electricity Regulation) and the ELT Contract would continue to apply thereafter, as originally drafted. However, no relief is afforded to allow for gradual ramp up of operations.

Given Market Renewal and climate change mitigation strategies remain subject to development, including any Clean Electricity Standard, the provisions would appear to be deficient and impose any resulting risks on the Supplier that would be hard to foresee or predict at this time.

CAPACITY CHECK TEST

In section 15.6 a (ii), unlike existing contracts, the capacity check test requires a test to be performed during Qualifying Hours. This restricts the window to business days between 07:00 and 23:00, limiting flexibility by the Supplier to find a suitable window to perform the test. The language further requires the test to be successful at ambient temperatures between -20C and +35C. The language further allows temperatures to exceed these extremes for up to half of the test hours. The cost of investing in new supply will not change in response to this provision. It will simply require Suppliers to amortize their costs over a much smaller capacity, despite these extreme temperatures only occurring an extremely small percentage of time. In APPrO's view, -10C and 30C during any available hours would be more suitable .

MONTHLY AVERAGE OFFERED QUANTITY (MAOQ)/AVAILABILITY

Limiting the MAOQ to 75% over 24 months could be restrictive should an unanticipated, long-duration outage occur at a facility. To allow for greater flexibility, APPrO recommends the IESO use 80% over a 36-month rolling period as this is in line with current Availability provisions in certain gas contracts (e.g., CES). The Non-Performance charges noted above provide plenty of incentive for a generator to be available as much as possible. The multi levels of risk layered on in the contract do not incent best maintenance practices required to keep the fleet operating reliably.

APPrO would welcome the opportunity to discuss its submission further with the IESO.

Sincerely,

David Butters
President & CEO