CRD Energy Consulting on Ontario Regulation 429/04 Amendments Related to the Treatment of Corporate Power Purchase Agreements ERO number 019-8666

Submission from: CRD Energy Consulting.

We congratulate the government on moving forward with the corporate power purchase agreement amendments. We see this as a first step in reducing IESO's reliance upon contracting new supply and the first opportunity to truly remove costs from the global adjustment (GA) rather than merely transferring such costs between ratepayers.

The pillars of our comments rest upon flexibility, certainty, simplicity, and reconciliation. We believe each of these philosophies must be embodied in the regulation. Recommendations are listed at the end, and we have responded to the Crown's questions upfront. Crown's questions:

1. Mechanics of Financial Settlement:

For there to be an uptake, the implementation for generators, customers, the IESO, and local distributors must be simple. An overly complex system will burden all participants and inhibit the achievement of the objective. The intent should be to improve the efficiency within the electricity industry.

The province should create a simplified process for new, smaller renewable projects that create Renewable Energy Credits (REC), are smaller than 5 MW, operate at a 50% or more capacity factor, and choose to be non-market participants. In our view, smaller projects should only deal with a single LDC for settlement and the customer. Further, filings should be the minimum required. Larger projects can manage more complicated settlement processes, which are reflected in the draft documents issued by the Crown.

The local LDC should determine the Installed Capacity and Capacity Factor for the connection point to optimize the local system benefit. Local utilities can incentivize this system benefit by seeking Ontario Energy Board (OEB) approval and charging the rate based on the cost of the benefit if related to the installation of a storage technology. REC can also be applied to enable natural gas generation to meet peak demand within the buyer's region and reduce carbon emissions to zero. One option for the province to consider is purchasing the REC at a set price from a new renewable generation and then having the natural gas cogeneration purchase the REC required to reach net zero from a provincial pool. If these conditions can be met, the buyer may pay the generator a negotiated rate for no less than 20 years.

If the province wishes to minimize smaller projects that are non-market participants, they could require 51% Indigenous ownership with a 50%+ capacity factor.

2. Municipal Support Resolutions:

Municipal Support resolutions should be geographically constrained to minimize unnecessary Red Tape. Furthermore, lands designated as Industrial should not require Municipal Support Resolutions but should instead pass the Provincial and Municipal Permits and Approvals processes.

Lands owned by the Provincial government (e.g., General Use) should not require Municipal Support Resolutions. Instead, the Crown should determine if the Municipality is impacted on a case-by-case basis. Both governments (Provincial and Municipal) can them agree that a Municipal Support Resolution is required, and if Indigenous Support and partnerships are also needed.

Federal and Indigenous lands should be exempt from the requirement to have a Municipal Support Resolution.

3. Location of Projects on Agricultural Lands:

Solar should be banned from all Agricultural lands. Other technologies must constrain their footprint to one acre per MW installed per 100 acres and demonstrate a capacity factor of 40% or better without storage.

Incentives should be implemented to have solar projects located on Brownfield lands and rooftops.

Flexibility:

We understand that the province needs more capacity and energy, depending on the time horizon. As such, the amendments must encourage both the construction of new generation and the demonstrable extension of the life of existing generation facilities. All renewables should be eligible to participate in the program if they meet minimum capacity factors. The regulation may put a 250kW minimum nameplate capacity on the program.

Given the limited ability of renewables to deliver capacity, multiple fuels can advance capacity certainty, e.g., combining solar with hydropower or adding batteries to solar. Further, additional capacity may be available through existing underutilized natural gas generators, which could purchase Renewable Energy Credits (REC) from new renewables to meet net-zero requirements and local peak demand. By allowing the combinations of resources, we can incentivize developers to make projects work rather than be stuck with a single fuel and enable the more efficient use of existing assets.

Further, flexibility requires different rules for projects of different sizes, say a large and small program where the large is greater than 5 MW. We chose 5 MW because the connection and payment details in current IESO contracts tend to change at that threshold. This would permit the policy to be targeted to different scales and thereby better match the prevalent technologies and development requirements (e.g., EASR) at that point.

Further, the program should remain available on an ongoing basis, limited only by the physical ability of the local grid to accept power delivery. Local Distribution Companies (LDC) would need to continue to maintain capacity availability information, and this physical restriction should be one of the restrictions on participation. The project capacity factor could also be a screening criterion for all projects that must meet a suitable capacity factor to connect to the distribution and transmission system. LDC could set the minimum capacity factor, which should be at 50% or higher. Program could also be contained to the powering of dams in southern Ontario, which have struggled in the IESO process.

Municipalities should be allowed to participate in two ways, which may require modifying section 142 of the *Electricity Act* or express authorization through the *Municipal Act.* Municipalities should be allowed to purchase new renewable electricity to meet their net-zero targets and build renewable generation within their boundaries.

Local Distribution Companies (LDC) should also be encouraged to defer capital obligations by connecting new renewable generation to their distribution system. If there is a system benefit, LDC should also be allowed to partner with the generator and build Storage that can be assigned to the rate base with OEB approval. LDC should also be allowed to purchase renewable energy within Ontario to meet its net-zero targets but be constrained to building its generation within its boundaries.

The federal government should also be allowed to purchase renewable electricity to meet its net-zero targets, mainly if the generation is located on Federal lands. For example, the author estimates 100+ MW of hydroelectric potential at federally-owned water control dams in Ontario, with a capacity factor of +50%. Very little is required other than allowing the Federal government to procure electricity using a Bilateral PPA; federal procurement is a mature organization that can manage the rest of the process. Another benefit of this step is that it allows projects to acquire PPA from the federal government, enabling federal funding.

Municipalities and Federal purchases will enable the market to develop long-term contracts, which will encourage the construction of hydroelectric. Hydroelectric has not aligned well with the IESO programs because the market is challenged by a prolonged building of hydroelectric power and its 150-year operational lifespan before refurbishment. However, municipalities and the Federal governments need to reach net zero and can see the value in securing a stable source of renewable electricity over the long term.

Certainty

We know new generation will not be constructed if the generator can only receive the HOEP (leave aside Market Renewal changes). As such, we understand the generator will have to rely upon the value of any emissions-related attributes (e.g., REC) and a portion of the global adjustment that the customer will save in addition to HOEP. The difficulty, especially in a market with so many uncertainties, is assessing the value of such to convince lenders to support the project.

Global Adjustment charges are predicated on the relative demand of the customer during the five (5) peak hours specified in the regulation. These 5 hours are not fixed and will undoubtedly move over time. For renewable generation, the production depends upon the nature of the fuel source and the magnitude of that resource during the particular 5 hours. To address the uncertainty, the appropriate and necessary way to alleviate this problem is to provide a minimum Global Adjustment capacity reduction based on the fuel source and capacity of the generator. This would ensure that both the customer and the generator understand the potential benefit of entering into the contract that can be relied upon.

Second, the ICI program is a regulation that can be cancelled. The transfer of costs from large to small consumers caused by the ICI program is not sustainable. Providing Class A customers with the opportunity to transition to purchasing their electricity from new renewable sources is a way for the province to move away from the ICI program.

Third, we know that HOEP and Global Adjustment are somewhat inversely related. As such, there should be a minimum amount—a floor amount—for the average combination of these amounts. This would provide some certainty on a minimum revenue.

Finally, if the policy requires that specific capacity be online during the five hours, the province will make the renewables reliant upon battery storage -- based on our understanding of the proposal. Reliance upon new batteries will further add to the cost of the generation. The province should consider natural gas cogeneration for the capacity to be available, with the natural gas reaching net zero by purchasing REC or sequestering. This would make capacity available at the most affordable price while stimulating new renewable energy. One option for the province to consider is purchasing the REC at a set price from a new renewable generation and then having the latest natural gas cogeneration purchase the REC required to reach net zero from a provincial pool.

Simplicity

In order for the potential to be uptaken, the implementation for generators, customers, the IESO, and local distributors must be simple. An overly complex system will burden all participants and inhibit the achievement of the objective. The intent should be to improve efficiency within the electricity industry.

As such, we think the settlement process for market participants will differ from that with non-market participants. In our view, smaller projects should only have to deal with a single LDC for settlement and the customer. Further, filings should be the minimum required. Larger projects may be able to manage more complicated settlement processes.

Indigenous Participation

Mirroring the IESO process, the province should encourage First Nation participation through grants and loans, which support and bolster Federal efforts. Fully leveraging federal programs can deliver high-capacity generation at lower prices, support reconciliation, and build capacity in the Communities.

Timing:

Federal funding programs will be available in 2024. Bilateral PPA rules should be announced so proponents can apply for funding.

Summary

We recognize that this could be a complicated regulation to draft. After seeing it implemented, the province may seek to roll out the regulation for smaller projects and build on the program. We have also summarized our recommendation below.

Summary of Recommendations:

1. Divide the Bilateral PPA program into large and small, with Small being 5 MW or less with a capacity factor of 50% or more.
2. Pilot with Small projects and then expand to projects over 5 MW using the more complicated process proposed in the draft document.
3. Coordinate the program with IESO procurement efforts and allow Bilateral Power Purchase Agreements to transfer to IESO programs. The purpose is to gravitate to an actual price for new electricity and meet demand and capacity requirements.

4. Allow a Global Adjustment capacity reduction based on the fuel source and capacity of the generator. If 100% of the Class A customer's electricity is purchased from new renewables, then the Class A customer would be insulated from any changes or cancellations of the ICI program.
5. The Capacity Factor of the Bilateral PPA projects should reach a minimum—we suggest 50%. Otherwise, the Distribution and Transmission system will clog with intermittent power projects that can impede IESO procurement plans and demand additional Storage.
6. If Renewable Generation is in an area other than the buyer's, allow the local LDC to determine the peak requirements, if any.
7. Allow Municipalities to purchase new renewable electricity from generators.
8. Allow Municipal governments and/or their LDCs to build renewable generation within their borders and sell it to a Class A customer.
9. Allow LDC to enable private generation by adding Storage to a renewable energy project. Pending OEB approval, the Storage is then paid through the rate base.
10. Allow LDC to purchase renewable electricity from generators within Ontario – could be capped to the small projects.
11. Enable the Federal government to procure electricity from new renewable generation, mainly if it is located on Federal lands – could be limited to powering of existing dams. The federal government could be a Pilot for the program with other Class A customers.
12. Allow existing Natural Gas Cogeneration to provide peaking services to meet Class A purchasers' ICI obligations. However, Net Zero must be reached by the purchase of the REC by the Natural Gas cogeneration project.
13. Leveraging federal programs and the provincial Aboriginal Loan Guarantee program fully will promote Indigenous partnerships, reconciliation, and capacity building.
14. Allow the development of Small Projects if majority owned by a Indigenous Community.