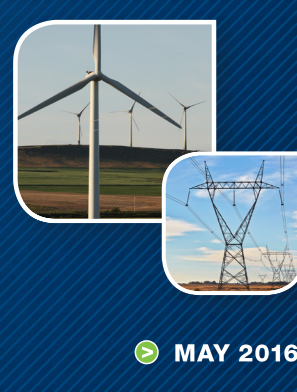
AESO ALBERTA ELECTRIC SYSTEM OPERATOR

Renewable Electricity Program Recommendations



MAY 2016

Table of contents

1.0 Executive summary

1.0 Executive summary

On January 26, 2016, the Government of Alberta directed the Alberta Electric System Operator (AESO) to design and implement a plan to incent the development of new renewable electricity generation projects in Alberta by 2030.

1.1 GOVERNMENT OF ALBERTA DIRECTION

The Government of Alberta's (GoA) aim under its Climate Leadership Plan (CLP) announced on November 22, 2015 is to transition Alberta away from carbon-intensive electricity generated by coal and toward lower-emission sources of electricity. On January 26, 2016, the GoA directed the Alberta Electric System Operator (AESO) to design and implement a plan to incent the development of new renewable electricity generation projects in Alberta by 2030.

The GoA stated that the program should use a competitive process to procure the renewable attributes from these new renewable electricity generation projects in order to keep the costs of the program as low as possible. It also indicated that the program should be managed and operated in concert with the retirement of current coal generating units. The GoA further stated that it has not chosen to fundamentally alter the current wholesale electricity market structure.

The AESO has developed the Renewable Electricity Program (Program) to meet these objectives. It proposes that periodic volumes of renewable attributes be procured through a competitive process, where renewable electricity generation developers compete with one another to provide these renewable attributes at the lowest cost possible. This document describes how the Program will work, and includes advice and recommendations about the first competition.

The AESO is committed to working with the GoA on this important initiative. Effective collaboration and coordination is needed to meet critical milestones and achieve the desired outcomes.

The AESO is committed to working with the GoA on this important initiative. Effective collaboration and coordination is needed to meet critical milestones and achieve the desired outcomes.

1.2 AESO RECOMMENDATIONS

The AESO is making recommendations with respect to the following:

- The Renewable Electricity Program design;
- The form and content of the competitive process that will be used to implement the Program; and
- Key features of the first competition, including a payment mechanism.

1.2.1 Renewable Electricity Program design

The AESO recommends that the Program is designed to be robust, flexible, sustainable and scalable in order to incent the development of renewable electricity generation projects through a series of competitions which will run between 2016 and 2030. The aim of the Program is to increase the amount of renewable electricity generation on the Alberta grid.

The focus of the Program is to procure the renewable attributes (which are produced by an electrical generation facility if it uses a renewable fuel source) that are generated from renewable projects. The volume of renewable attributes to be procured in any given competition may be linked closely with coal unit retirements where it makes sense to do so. Existing, planned and approved transmission will be utilized first in order to minimize cost impacts to Albertans. The AESO will also develop, prior to the first competition, a reporting and recommendation process to track progress towards the 2030 target. This process will provide the GoA with frequent and ongoing visibility of progress and costs.

As the AESO designed the Program, it was critically important to consider and assess the potential impacts of Alberta's current electricity investment climate (i.e. the impact of pool price uncertainty prevailing today) on the Program in light of the province's transition to a lower-carbon future. Therefore, certain aspects of the Program have been purposefully designed to address these potential impacts.

1.2.2 Stages of the competitive process

The AESO recommends that each competition may have up to three stages:

- A Request for Expressions of Interest (REOI), a discretionary stage where the AESO can gauge interest in participating in the competition;
- A Request for Qualifications (RFQ), where bidders submit their qualifications including their project proposals; and
- A Request for Proposals (RFP), where bidders qualified in the preceding stage confirm no changes to their bid teams or their projects and submit a final offer for support.

1.2.3 Payment mechanism

The AESO assessed a number of possible payment mechanisms that could be used to incent the development of renewable electricity generation. The three mechanisms the AESO wishes to highlight are described below:

1) A Fixed Renewable Energy Credit (Fixed REC) mechanism, whereby winning bidders are paid a $/MWh payment as bid, for renewable attributes produced.
2) An Indexed Renewable Energy Credit (Indexed REC) mechanism, whereby winning bidders are paid a $/MWh payment for renewable attributes produced. The payment to winning bidders is calculated as the difference between a strike price[1] as bid and a reference price (e.g. pool price).
3) A Capacity Payment mechanism, whereby winning bidders are paid a $/MW for capacity built. These payments would not be dependent on the production of electricity and would be more akin to a capital contribution.

[1] The strike price, expressed in $/MWh, is in essence a bidder's lowest acceptable cost for the renewable project the bidder plans to advance.

1.2.4 The first competition

The AESO recommends that the first competition:

- Require projects to be in service in 2019 (as directed by the GoA). In order to achieve this objective, the AESO has determined that the first competition should be launched by the end of 2016;
- Will include an REOI, RFQ and RFP;
- Be open to all renewable technologies (i.e. fuel neutral);
- Be applicable to new and expanded renewable projects located in Alberta;
- Require projects to be greater than or equal to 5 MW;
- Procure a volume between 200 MW and 400 MW;
- Include selection criteria that focuses on financial and technical considerations only;
- Be governed by an affordability threshold[2] in order to manage costs;
- Have a contract term of 20 years to support financeability of the projects;
- Be planned for areas where there is enough capacity on the transmission or distribution system to accommodate the generation from these projects; and
- Utilize an Indexed REC payment mechanism. This mechanism is recommended because it is most likely to draw the highest number of competitors and minimize the total cost of the first competition.

1.3 LEGISLATIVE CHANGES REQUIRED

To implement the Program, changes to the *Electric Utilities Act* (EUA) are required since there are currently no provisions to specifically incent renewable generation or implement other aspects of the Program design. The legislative changes the AESO is seeking are intended to:

- Give the AESO authority to implement the Program;
- Maintain investor interest and confidence in the current market framework;
- Integrate the Program into the current market framework; and
- Help ensure that the Program can be implemented in a timely and efficient manner with minimal legal and regulatory risk, and achieve regulatory efficiency.

These changes will need to be approved at the 2016 fall sitting of the legislature. Delay could significantly impact Program timelines, most notably having renewable projects in service in 2019.

[2] An affordability threshold identifies the threshold above which the value of bid prices may be determined to be unaffordable. The threshold can be expressed as a $/MWh and/or the total costs that may be allocated to each procurement. An affordability threshold that targets total cost will need to work in concert with volume targets.

Alberta must be able to compete with other Canadian and American jurisdictions, and the Program must be able to attract investment dollars to the province.

1.4 RESEARCH AND ENGAGEMENT

The AESO's recommendations are based on research and engagement activities conducted between January and April 2016. This work began with a thorough review and consideration of the *Climate Leadership – Report to Minister* (Climate Leadership Advisory Panel report). The report proposes a payment for renewable attributes to incent greater amounts of renewable electricity generation capacity in Alberta. It points out that renewable technologies face challenges when competing with non-renewable generation within Alberta's current market structure. The report also states that in order to accelerate the development of new renewable generation, these challenges can be overcome by making projects compete for government support.

In February 2016, the AESO retained London Economics International LLC (LEI), a company with extensive expertise in the renewables sector, to study how other jurisdictions designed and implemented their renewable procurement programs. LEI's study yielded instructive insights about best practices and trends emerging from these jurisdictions; a discussion of how these practices and trends might apply in Alberta was also included. The jurisdictions chosen for the LEI study were Australia, California, New York, Ontario and the United Kingdom. All have used a centralized body to facilitate the addition of new renewable electricity projects to their systems. In each case, a procuring authority issues calls to the market for new renewable electricity generation projects.

In March 2016, the AESO posted a questionnaire on its website seeking feedback from developers, investors and other interested parties regarding their key considerations for investing in renewable electricity projects in Alberta. With 138 responses received, this exercise yielded extremely helpful insights about the circumstances respondents currently face in Alberta. It also identified information investors/developers are interested in, and the considerations they weigh when deciding whether to invest in Alberta. Of particular interest were the recurring themes of a need to improve investor/developer interest in Alberta, and the identification of a mechanism to provide revenue certainty for future investors/developers. This insight was framed in the North American context, where Alberta is one jurisdiction of many that is seeking to increase electricity generation from renewable sources. Alberta must be able to compete with other Canadian and American jurisdictions, and the Program must be able to attract investment dollars to the province.

The AESO was also interested in better understanding the perspectives of non-renewable investors/developers, existing non-renewable generators and capital market participants with respect to Alberta. Morrison Park Advisors (MPA), an independent banking advisory firm, conducted a survey of developers, owners and operators of non-renewable generation facilities to gauge their level of interest in investing in non-renewable generation projects in the province. Through their interviews, MPA has gathered views of these stakeholders to understand barriers to investing in Alberta and to determine possible ways to resolve them. The initial results of the interviews suggest that there has been a significant erosion of support for investing in "energy-only" markets in Alberta (and elsewhere) given market and policy uncertainty is undermining the investment community's confidence that revenues from the electricity market (i.e. the pool price) will be sufficient to earn a reasonable return.

The AESO also engaged with members of the lender (capital markets) community. In general, lenders indicated a preference to invest in projects with long-term contracted cash flows. Therefore, the current uncertainty in Alberta and volatility in the pool price make it very difficult to finance projects in an energy-only market. While renewable lenders are willing to take some operating and resource risk (e.g. for wind or solar projects) there is a high degree of discomfort taking price risks or financing merchant projects.

Regarding the payment mechanism, lenders believe the project economics are not workable at the current pool price with a Fixed REC of $35/MWh. All lenders who provided a response preferred an Indexed REC approach as the best way to achieve an effective cost of financing and capital structure.

Throughout the research and engagement phase, the AESO has provided continuous updates to the GoA with respect to its findings.

1.5 NEXT STEPS

The AESO will continue to work with the GoA to ensure legislation needed to implement the Program is in place before the first competition begins. The AESO will continue to engage stakeholders on matters related to the Program design and the first competition, such as agreement terms and other administrative matters, and will support the GoA on its engagement initiatives related to the CLP.

2.0 Introduction

2.0 Introduction

On November 22, 2015, the GoA announced its Climate Leadership Plan, a policy initiative designed to take action on climate change and protect the province's health, environment and economy.

2.1 PURPOSE

On November 22, 2015, the GoA announced its Climate Leadership Plan (CLP), a policy initiative designed to take action on climate change and protect the province's health, environment and economy. Within Alberta's electricity industry, implementation of the CLP will involve key initiatives, such as the phasing out of coal-fired power plant emissions and the introduction of a program to incent the development of renewable electricity generation through the purchase of renewable attributes. Given its critical role in the industry, the GoA tasked the AESO with advancing this work. The Renewable Electricity Program (Program) sets out the AESO's recommendations for incenting the development of renewable electricity generation.

> The Renewable Electricity Program sets out the AESO's recommendations for incenting the development of renewable electricity generation.

2.2 GOVERNMENT DIRECTION

On January 26, 2016 the AESO received a letter[3] from the Deputy Minister of Energy which provided the following direction and guidance:

- The AESO has been tasked to develop and implement a plan to bring on new renewable electricity generation capacity, in accordance with GoA direction, to the grid by 2030.
- The cost of support for renewables should be kept as low as possible through the use of a competitive process, such as an auction.
- The Program must be carefully managed and operated in concert with the retirement of current coal generating units.
- The GoA has not chosen to fundamentally alter the current wholesale electricity market structure.
- The AESO is to prepare a plan for review and consideration by the GoA no later than May 2016.
- The AESO is to continue to work closely with Alberta Energy (AE).

Additional direction and guidance on the overall Program and the first competition has been provided through ongoing discussions with AE. Further, the AESO has been mindful of the findings and recommendations in the Climate Leadership Advisory Panel report. The AESO's recommendations are therefore presented as:

- Recommendations related to the overall Program;
- Recommendations related to the generic competitive process that is intended to form the basis of each competition moving forward; and
- Recommendations specific to the key features of the first competition.

[3] The letter, addressed to the President and Chief Executive Officer of the AESO, dated January 26, 2016, is attached as Appendix A.

3.0 Renewable Electricity Program

3.0 Renewable Electricity Program

3.1 KEY HIGHLIGHTS

The GoA has provided direction to the AESO that the Program[4] be designed to meet the following objectives:

- The Program design must maximize competitive tensions, to the extent possible, to drive down the GoA's cost of support for renewable electricity generation;
- The Program must not jeopardize the performance and reliability of the Alberta Interconnected Electric System (AIES); and
- The Program design will consider the uniqueness of Alberta's energy market.

Based on ongoing collaboration with AE, the AESO recommends that the Program:

- Apply to renewable generation, as defined by Natural Resources Canada[5];
- Target utility-scale generation ($\geq$5 MW); and
- Be restricted to new or expanded projects that physically reside in Alberta.

3.2 OVERVIEW

The Program has been designed to incent the development of the required levels[6] of renewable electricity generation through a series of competitions where bidders compete for government support in exchange for a project's renewable attributes. Successful participants will be awarded renewable energy support agreements. Support payments will be payable by the AESO under such agreements in exchange for the transfer to the GoA of the renewable attributes associated with such projects[7]. Regardless of the renewable target chosen, in order to achieve both the GoA's short-term and long-term objectives for bringing renewable electricity generation capacity onto the AIES, the Program has been structured to be robust, flexible, sustainable and scalable over time.

[4] These are objectives that will remain static for the duration the Program is in place.

[5] www.nrcan.gc.ca

[6] The GoA has not yet confirmed the 2030 renewable electricity generation target or interim targets. It is the AESO's understanding that two options are being considered: a capacity target of 4,200 MW and an energy target (e.g. up to 30 per cent of provincial energy generation). The Program is designed to accommodate any target set by the GoA.

[7] As noted on p.49 of the Climate Leadership Advisory Panel report, "A clean power call is an open, competitive request for proposals for government support … with support provided through the government purchase of the renewable energy attributes of the power."

3.3 INSIGHTS FOR PROGRAM DESIGN

There are several key recommendations noted in the LEI report, and reiterated by stakeholders through the AESO's ongoing engagement activities, that the AESO believes should be adopted for the Program. These recommendations incorporate best practices and key information sought after by developers and investors that will likely contribute to the successful long-term implementation of the Program in Alberta.

Firstly, most jurisdictions establish an overall target as well as interim targets with respect to the ultimate penetration of renewables a jurisdiction is looking to achieve. The jurisdictions reviewed have set their targets using different approaches; however, a common approach is to embed such targets into legislation. The AESO is supportive of this approach as the developer and investor communities have indicated interest is enhanced in programs where there are multiple opportunities to participate and be successful. While the AESO is an advocate of legislating either an overall target or interim targets, it does not believe it is necessary or beneficial to legislate the frequency of procurements.

A second best practice is to be transparent with industry regarding the competitions. Even if the specific details of each competition over the next several years have not yet been determined, there may be themes or comments of general application that can be made available to provide greater certainty to both potential renewable and non-renewable developers to assist with their short-term and long-term investment decisions.

It will be important for industry to understand whether:

- The objectives for each competition will remain mostly consistent;
- The majority of competitions will be fuel neutral; and
- The volume being procured in any given competition will be relatively consistent.

The AESO recognizes that at this stage the coal emissions phase-out plan is not yet fully defined. However, the competition schedule for renewables over the coming years will be informed by this plan. Given the AESO's mandate to ensure the ongoing reliability of the AIES and its involvement with both the coal retirement process and the Program, the AESO believes it is best positioned to develop the schedule of competitions once more details regarding the coal retirement plan are known. This schedule of competitions may be updated from time to time as new information becomes available. Even though the coal phase-out plan has not yet been finalized, this does not preclude the AESO from proceeding with the first competition.

A third item of note is that jurisdictions which have more mature renewable programs have seen these programs evolve over time. For example, in Ontario, government direction drove the rapid adoption of new renewable generation through the Feed-in-Tariff framework. More recently, in response to changing government priorities, the Large Renewables Procurement Program has been introduced for the purposes of sourcing new renewable generation at the lowest possible cost. In the United Kingdom, the initial Renewables Obligation Regime (an administrative program in place during the early-to-mid-2000s) provided generators 60 to 75 per cent of their cash flows. This program has now transformed into one where renewable generation is competitively sourced. Winning generators are then compensated using a contract for differences mechanism whereby all cash flows are contracted. This new approach removes merchant price risk for the generator and reaps other benefits such as a decrease in financing costs for these projects. As a result, there is precedent in industry for programs to be refined as they mature.

It is broadly recognized that there is a high degree of uncertainty about the economic and business environments in Alberta as the province transitions to a lower-carbon future. Therefore, the AESO's recommendations regarding the early competitions will reflect this reality.

4.0 Generic competitive process

4.0 Generic competitive process

4.1 KEY HIGHLIGHTS

The AESO recommends the following objectives for the generic competitive process:

- Utilize competitive market forces to drive down the GoA's cost of support for renewable electricity generation;
- Be fair and transparent;
- Remove barriers to entry, where appropriate, in order to maximize the number of competitors;
- Be straightforward and efficient; and
- Allocate risk to those best able to manage it.

The AESO further recommends the following key features:

- A three-stage competition consisting of an REOI (discretionary), RFQ and RFP; and
- Process oversight provided by a Fairness Advisor.

4.2 OVERVIEW

The design of the generic competitive process considered objectives for the Program, procurement best practices, key learnings demonstrated by other jurisdictions that have embarked on similar types of programs, stakeholder feedback and the AESO's prior experience in running procurement competitions for large-scale infrastructure and ancillary services.

The AESO has in-depth experience with developing and implementing competitions of varying sizes. For example, in 2010 the GoA mandated the AESO to develop and implement a competitive process for certain bulk transmission projects. This process was first applied to the Fort McMurray West 500 kV Transmission Project, which was successfully awarded in December 2014. In addition, to manage the day-to-day operations of the AIES, the AESO is mandated to procure ancillary services (such as operating reserves, transmission must-run, black start and load shed services for import) via a competitive procurement process whenever possible[8].

[8] Some ancillary services are location-specific and may only be provided by specific generators. In these cases it is not feasible to run a competitive process.

The AESO recommends that the generic competitive process be comprised of up to three stages: an REOI, RFQ and RFP. Further, the AESO recommends that while an RFQ and RFP are mandatory stages for each competition, discretion is retained with respect to whether or not an REOI will be issued for any given competition. The AESO anticipates that a competition comprised of all three stages would normally last approximately 7–11 months.

REOI **STAGE 1**	**Request for Expressions of Interest** **4–6 WEEKS** ▪ Attracts interest ▪ Gauges level of interest ▪ No obligation
RFQ **STAGE 2**	**Request for Qualifications** **4–6 MONTHS** ▪ Determines bidders qualified to proceed to RFP stage
RFP **STAGE 3**	**Request for Proposals** **2–3 MONTHS** ▪ Only qualified RFQ bidders may participate in RFP stage ▪ Bidders confirm that no changes have occurred since RFQ submission ▪ Bidders submit final offers

4.3 FRAMEWORK FOR THE GENERIC COMPETITIVE PROCESS

Similar to the design of the overall Program, the AESO relied on a number of sources to inform the framework for the generic competitive process. Best practices demonstrated in other jurisdictions were heavily favoured when considering the design of the Program.

Staged competitive processes (i.e. progressing from an REOI to RFP) are typical to most major procurements, including the processes undertaken in the jurisdictions reviewed by LEI. They offer benefits to the authority conducting the process as well as to participants. A staged competition will offer the AESO greater oversight, and give more ample and frequent opportunities to respond to the needs of bidders or the GoA as the competition progresses. Furthermore, staged competitions are very familiar to bidders of renewable programs, the GoA and to the AESO, which already implements such processes for bulk transmission infrastructure and ancillary services. While the product being procured may be relatively new in Alberta, the structure of the process will not be, thereby helping to provide bidders a level of confidence in the Program. Lastly, staged competitions can be very flexible, and as the Program and its associated objectives develop over time, the staged competition approach will be able to accommodate these developments relatively easily, and without changing the structure with which bidders will have become familiar.

Breaking up a competition into three stages also offers efficiency benefits. Managing a competition requires a significant investment of time and resources by both the authority and bidders, particularly at the RFQ and RFP stages. It is helpful to have a process that continues to screen parties from all those who may be interested (gauged through an REOI) to only those who are qualified to provide pricing and be awarded a final support agreement (at the conclusion of the RFP stage).

From the AESO's perspective, a staged process will provide a greater number of opportunities to communicate competition expectations to the market and to seek meaningful feedback from potential participants and their lenders. A better understanding of expectations on both sides will firstly allow the AESO to better gauge market interest and draft competition and agreement documentation with appropriate risk allocations. Secondly, it allows participants to more effectively scope their projects and draft their submissions, in each case increasing the likelihood potential participants will submit qualified proposals. This increases competition and the likelihood of achieving success. For participants, a staged process also permits sufficient time for interested parties to obtain the resources they may require to participate.

4.3.1 Request for Expressions of Interest (REOI)

The principal objective of the REOI stage is to attract interest in the competition and to inform the market of key aspects of the competition. The level of response to the REOI provides the AESO (and the GoA) with insight regarding the market's interest in the competition. The responses can also provide helpful information about which parties intend to participate. The information provided by the AESO in an REOI document, determined at the AESO's discretion, is intended to provide a sense of timing of subsequent competition stages (i.e. RFQ and RFP), assist potential participants in determining whether they wish to participate in the competition, and give an indication of the level of commitment likely to be required at subsequent stages of the process. The REOI is non-binding, and is most helpful for less mature competitions. The REOI stage may last 4–6 weeks.

4.3.2 Request for Qualifications (RFQ)

The principal objective of the RFQ stage is to identify, from among those participants who responded, the participants and projects eligible to participate in the RFP. The RFQ stage allows the AESO to evaluate financial, technical and other eligibility requirements of participants and their proposed projects, and ensures that the project being bid is likely to be completed by the specified in-service date.

Evaluation of RFQ submissions may occur through both pass/fail elements as well as through scoring. For example, a participant may be assessed on a pass/fail basis with respect to its financial capacity, and scored on technical elements such as their level of experience in project development. The RFQ stage is expected to be the most resource-intensive stage for participants and the AESO. It is anticipated to last 4–6 months.

4.3.3 Request for Proposals (RFP)

The RFP will be the final stage of the generic competitive process, open only to those participants who qualified as part of the RFQ. Essentially a pricing stage, the RFP will require participants to confirm that there have been no changes in the participant's bid team or the proposed project since the RFQ stage (i.e. that they remain qualified) and to provide a final offer. Qualified participants will be evaluated based on price, with the successful or winning participants being given the opportunity to enter into a renewable electricity support agreement. The RFP stage of the competition is anticipated to last 2–3 months.

For the stages of the competition where the AESO and each of the bidders will commit to certain obligations (namely, at the RFQ and RFP stages), the AESO anticipates including terms that reserve certain rights for the AESO. These terms, commonly used in staged competitions and often referred to as "privilege clauses," provide the AESO the needed amount of control over the process; for example, choosing not to proceed if there is insufficient interest, or not awarding a project if there is only one qualified project. The exact nature of these clauses will be determined as the competition documents are developed, and will be familiar to most bidders.

4.4 KEY DETAILS REGARDING THE FRAMEWORK

A more detailed breakdown of each of the REOI, RFQ and RFP stages, in addition to considerations that the AESO believes are important to address at each stage, is provided below.

TABLE 1: Generic competitive process

All stages

- **All stages of each competitive process will be overseen by a Fairness Advisor**
- **The AESO reserves the right to disqualify any participant exhibiting anti-competitive behaviour**
- **Evaluation may require expertise external to the AESO**

Considerations

- Oversight by a Fairness Advisor provides confidence to participants that they are engaged in a fair competition, and ensures the AESO has the right to disqualify anyone engaged in anti-competitive behaviour (such as collusion). Vital to ensuring robust competition, these features are viewed as important best practices for competitive procurements.
- The AESO plans to recruit and leverage expert evaluators where appropriate (e.g. capital markets and technical expertise).

Stage 1: Request for Expressions of Interest (REOI)

- **Informs industry of the upcoming competition**
- **Provides a formal opportunity for market feedback**
- **Duration: 4–6 weeks**

Considerations

- Provides an early indicator of interest in the Alberta market and the other jurisdictions that Alberta may be competing with for investment.
- Provides comfort to the market that a clear and transparent competitive process has been developed, with critical information being provided to all potentially interested parties. This allows the market to make an informed decision to participate and is a feature of many other successful renewable competitions.
- Provides an opportunity for market feedback on the intended approach to the competition, including commercial heads of terms (considered a best practice) and is an important contribution towards timely and successful RFQ/RFP stages, especially for the first series of competitions.
- Supports competition best practice by minimizing the potential for bilateral negotiations during later stages of the procurement.

Stage 2: Request for Qualifications (RFQ)

- **Informs RFQ bidders of eligibility requirements**
- **Allows the AESO to determine if bidders are eligible and therefore qualified to proceed to the RFP stage**
- **Duration: 4–6 months depending on the number of bidders**

Considerations

- Bidders must pay a non-refundable qualification fee to participate – this deters frivolous bids and provides a strong indicator of bidder commitment. Requiring this upfront financial commitment is a best practice for larger competitions, helping to ensure the RFQ process is a meaningful and effective one, by qualifying only those bidders likely to successfully participate in the RFP stage.
- Bidders must describe the composition of their project teams.

- Bidders must demonstrate their qualifications in the following three categories (at a minimum): (1) project eligibility, (2) financial strength and capability, and (3) technical capability. The more straightforward the qualification process, the more likely projects will be able to meet the thresholds set out in the evaluation criteria. The experiences of other jurisdictions (such as Ontario) have indicated that increasing the complexity of qualification criteria (specifically as they may relate to meeting certain socio-economic criteria) also increases the complexity and cost of monitoring successful projects once the RFP stage has been completed.
- **Project Eligibility:** the bidder's proposed project must meet the prescribed eligibility criteria for the procurement, including criteria such as:
    1) Is the project developed using technology that meets the prescribed definition of renewable;
    2) Is the project a new or expanded development (i.e. existing projects are not eligible);
    3) Is the project situated in Alberta;
    4) Is the project utility-scale (≥5 MW);
    5) Is the project likely to achieve a specified in-service date (e.g. 2019) based on activities completed to date and a demonstrated understanding of activities yet to be completed; and
    6) Does the project require new transmission system or distribution system investment.
- **Financial Strength and Capability:** the bidder must demonstrate that it has the financial strength to develop the project, consisting of:
    1) Sufficient net worth relative to the proposed project size by reference to current and historic financial statements;
    2) Confirmation that no event is ongoing or reasonably foreseeable that could have a material adverse impact on the bidder's current financial standing;
    3) Confirmation from any financial sponsor or guarantor of its willingness to provide such support; and
    4) Confirmation of the equity contribution and a description of how the bidder intends to secure the equity contribution necessary to construct the project.
- **Technical Capability:** the bidder must demonstrate that it has the technical capability and capacity to develop its proposed project, consisting of:
    1) Involvement in a number of recent projects of similar size and/or complexity;
    2) Experience in each stage of project development (e.g. siting, stakeholder consultation, land acquisition, etc.), construction and operation; and
    3) A narrative description of the relevance of the bidder's experience to its proposed project.
- Qualified bidders will be required to achieve a pass in each qualification criterion in order to proceed to the RFP stage. A pass/fail approach is an evaluation standard that:
    1) Recognizes that a minimum standard is appropriate for each evaluation category and that excellence in one category cannot compensate for weakness in another;
    2) Is easily understood by the market; and
    3) Is relatively simple to administer.

These features are important elements of a transparent and objective evaluation approach, which past experience in Alberta and other jurisdictions has recognized as being best practices.

The duration of the RFQ stage will range from 4–6 months, with the critical element being providing enough time for bidders to prepare a robust response. In other jurisdictions, timelines have been adjusted depending on the maturity of the process and bidders, generally shortening with each subsequent competition.

Stage 3: Request for Proposals (RFP)

- **Only qualified RFQ bidders may proceed to the RFP stage**
- **Confirmations that no changes have occurred since RFQ submission**
- **Stricter financial commitments with respect to equity**
- **Submission of final offers**

Considerations

- Bid security must be provided in conjunction with RFP submissions – security is returned either when a bidder is not selected or a successful bidder achieves financial close[9].
- Bidder must confirm that the composition of its project team is unchanged since RFQ submission. This helps minimize "gaming" whereby a qualified project team is changed during the RFP stage, and is one of the ways that non-competitive behaviour is discouraged.
- Bidder must provide updated financial undertakings to demonstrate that no event has occurred (or is reasonably expected to occur) since the RFQ submission that could have a material adverse impact on its financial standing.
- Stricter financial commitments are required in respect to all (or a material portion of) the proposed equity contributions.
- Bidder must provide a binding offer (i.e. bid price).
- Bidders who remain qualified will be selected based on lowest price (subject to any affordability ceiling).

4.5 PAYMENT MECHANISM

In addition to the key details noted in Table 1 above, the payment mechanism is another critical component of any specific competition. The AESO assessed a number of possible payment mechanisms that could be used to incent the development of renewable electricity generation. The three mechanisms the AESO wishes to highlight are:

1) A Fixed Renewable Energy Credit (Fixed REC) mechanism, whereby a winning bidder is paid a $/MWh payment as bid, for renewable attributes produced[10].
   - The Fixed REC as bid, is intended to close the gap between the pool price and the cost of the renewable project.
2) An Indexed Renewable Energy Credit[11] (Indexed REC) mechanism, whereby a winning bidder is paid a $/MWh payment for renewable attributes produced as follows:
   - Winning bidder bids a price that is, in essence, its lowest acceptable cost for the renewable project the bidder plans to advance;
   - The dollar value of support paid to the winning bidder for renewable attributes produced by that project is not the bid price. It is calculated by subtracting a reference price[12] (e.g. the pool price) from the bid price.

Sample calculation

BID PRICE	–	REFERENCE PRICE	=	SUPPORT PAYMENT $ VALUE
$80/MWh		$30/MWh		$50/MWh*

**The difference of $50/MWh represents the value of the support payment.*

[9] Financial close occurs on the date when all conditions precedent to advancing the loan have been satisfied.

[10] This is above and beyond revenue received from the energy market for energy delivered.

[11] This mechanism is sometimes referred to as a contract for differences structure in other jurisdictions.

[12] When the bid price exceeds the reference price (e.g. the pool price), bidders would be paid the difference for the renewable attributes. When the pool price exceeds the bid price, bidders would pay the GoA the difference.

   - Given that new renewable generation projects face financing challenges in today's market environment, the difference is intended to close the gap between the pool price and the cost of the renewable project. Winning bidders will not face merchant price risk, nor will they benefit from merchant price opportunity; and
   - The consideration for the support payment is the renewable attribute. The support payment is not consideration for the underlying commodity, namely the electrical energy, or the capacity used to generate electrical energy.

3) A Capacity Payment mechanism, whereby a winning bidder is paid a $/MW for capacity built as compensation for the renewable attribute. These payments would not be dependent on the production of electricity and would be more akin to a capital contribution.

The Capacity Payment mechanism was considered the least favourable. The Program is intended to incent the development of electricity generation facilities that create renewable attributes (a key GoA objective for the Program) and therefore defining the cost or value of the renewable attribute under this mechanism would be difficult.

In a pricing environment where lenders place limited value on the pool price and the associated revenue stream, bidders are expected to bid up the price of the capacity payment. In this circumstance, there is a high likelihood that the support payments would be substantial. This would be a costly solution for Albertans.

In addition, the majority of renewable forms of generation are intermittent (e.g. wind, solar) and therefore the variability of how these generation sources may be dispatched is also somewhat inconsistent with the typical rationale for capacity payments (i.e. capacity payments provide compensation for being available).

Finally, the Capacity Payment mechanism is likely to result in payments getting out of step with the pool price, which would result in future windfalls for winning bidders. Given the current economic environment, bidders are likely to include risk premiums in their bid prices to reflect pool price uncertainty. As pool price rises over time, bidders would receive a higher pool price for electricity produced in addition to the support provided by the capacity payment. This could result in windfall gains.

For these reasons, the AESO did not further consider the Capacity Payment mechanism as a recommended option. The AESO concentrated its assessment on the Fixed REC and Indexed REC payment mechanisms. A detailed comparison of the two is provided in Table 2.

TABLE 2: Fixed REC and Indexed REC comparison

Program objectives and important outcomes	Fixed REC $/MWh	Indexed REC +/- $/MWh on Difference
Maximize number of bidders **Maximize competitive pressures** **Drive prices down**	▪ May limit the number of bidders based on financeability. This mechanism is unlikely to provide sufficient revenue certainty required for project financing schemes unless the Fixed REC is uncapped.	▪ Will likely attract the greatest number of bidders based on financeability (e.g. will encourage financial innovation and allow project financed solutions versus just balance sheet solutions) and competition will drive prices down. ▪ In other jurisdictions, a large portion of renewable developers rely on project finance as the financial structure underpinning renewable generation projects.
Allocation of risk[13] **Recognition of temporary period of significant uncertainty as electricity industry transitions**	▪ Not expected to significantly alter the allocation of risk between a generator and the GoA; however, it depends on bid pricing. ▪ In a low-priced and uncertain pricing environment, the REC value as bid may be driven up, implicitly transferring risk previously held by generators to the GoA. ▪ Development, construction and operations and maintenance risk, in addition to pool price risk, will reside with the developer.	▪ Allocates market price risk and opportunity to the GoA. ▪ Development risk (including siting), construction risk and ongoing operations and maintenance risk continue to reside with the developer.
Alignment with current market structure	▪ Aligns with current market structure. ▪ The support payment is the investment signal. ▪ With a current pool price floor of $0, dispatch signal does not change. ▪ Incents superior locational choices to optimize exposure to price discount/premium and maximize production. ▪ Will likely result in other generators demanding the same treatment (i.e. some sort of guaranteed revenue stream).	▪ Less aligned with current market structure; however, is not expected to fundamentally alter the market. ▪ The support payment is the investment signal. ▪ With a current pool price floor of $0, dispatch signal does not change. ▪ Incents locational choices to maximize production. Consideration of price discount/premiums not a factor. ▪ Will likely result in other generators demanding the same treatment (i.e. some sort of guaranteed revenue stream).
Easily understood by public	▪ Approach is easily understood by public.	▪ Approach may be more difficult to understand by public.

[13] For purposes of any specific competition, the principle of allocating risk to those best able to manage it minimizes the inclusion of significant risk premiums in bid prices. Given the significant uncertainties in Alberta's electricity market today, a payment mechanism that allows for the transfer of this risk may result in the lowest cost solution.

Program objectives and important outcomes	Fixed REC $/MWh	Indexed REC +/- $/MWh on Difference
Fixed funding requirements	▪ Funding requirements are, for the most part, fixed and easily identifiable. ▪ Funding levels can be managed through the procurement of specific volumes in each competition.	▪ Funding requirements are capped at strike price, but will vary year-to-year as pool price changes. ▪ Funding requirements can be forecast by AESO 1–2 years in advance.
Out of step with market[14]	▪ May get out of step as pool price rises over time and may drive up the aggregate cost of support associated with each procurement.	▪ Will not get out of step as support payment adjusts with changes in pool price. As pool price rises, support payments fall and could result in a net payment to the GoA.
Alignment with Climate Leadership Advisory Panel report	▪ Aligns with the Climate Leadership Advisory Panel's recommendation, unless cap is removed.	▪ Partially aligns with Climate Leadership Advisory Panel's recommendation as it provides compensation for the production of renewable energy attributes. ▪ Allocation of price risk differs.
Competition with other jurisdictions	▪ Used in other jurisdictions where multiple streams of revenue may be more readily available to provide revenue certainty.	▪ Aligns with other jurisdictions that provide revenue certainty.
Moving to an alternative payment mechanism	▪ Movement to an Indexed REC from a Fixed REC at a future point will likely not result in resistance.	▪ Movement to a Fixed REC from an Indexed REC in the future may encounter more resistance.

As noted in the table above, each mechanism has strengths and weaknesses relative to the Program objectives and other outcomes that may be important to the GoA.

With respect to the current uncertainty in Alberta, an assessment of the suitability of the payment mechanism for the Program should consider the potential outcomes and impacts of choosing a Fixed REC which could take two forms: capped or uncapped. Table 3 provides an illustration of the possible outcomes of choosing a capped or uncapped Fixed REC in light of the current market environment in Alberta.

[14] The support payment arising from the Indexed REC is designed to adjust with changes in market prices. The strike price as bid is subject to competitive market pressures that puts downward pressure on the strike price in the first instance. Support payments then adjust with changes in pool price.

TABLE 3: Capped and uncapped Fixed REC comparison

Fixed REC	Key risks
Scenario 1 Capped Fixed REC	▪ Cap chosen is too low given merchant risk (i.e. uncertainty about pool price risk may cause lenders to value it at near zero) and no/few bidders participate in procurement.
	▪ Advancement toward target is significantly hindered.
Scenario 2 Uncapped Fixed REC	▪ Fixed REC value is very high (e.g. >70 per cent of long-term levelized costs) relative to GoA expectations. This may limit the volume of renewables the AESO can procure during a competition, given the GoA may have a cap on budget dollars allocated to the Program and may hinder advancement toward target.
	▪ AESO may be unable to procure the necessary volumes of renewables so that there is alignment with the pace of coal retirement.
	▪ It will likely result in windfall profits to winning bidders as pool price rises.

The AESO designed the Program to accommodate either a Fixed or Indexed REC payment mechanism. The AESO will recommend the most appropriate mechanism in its discussion of the first competition in Section 5.0.

Section 4.6 provides a more detailed discussion of how the payment mechanism may contribute to a reduction in the overall cost of a competition.

4.6 PROGRAM COST CONSIDERATIONS

The AESO recognizes that the cost of the Program will be important to the GoA and to Albertans. To set the stage for considering the cost of the Program, this section provides an illustration of the levelized cost of renewable electricity generation projects and the impact of the selected payment mechanism on cost[15].

4.6.1 Levelized costs

The AESO's financial advisor, KPMG, estimates that the levelized cost of wind projects is likely to be in the range of $74/MWh to $101/MWh, with an expected value of approximately $80/MWh.

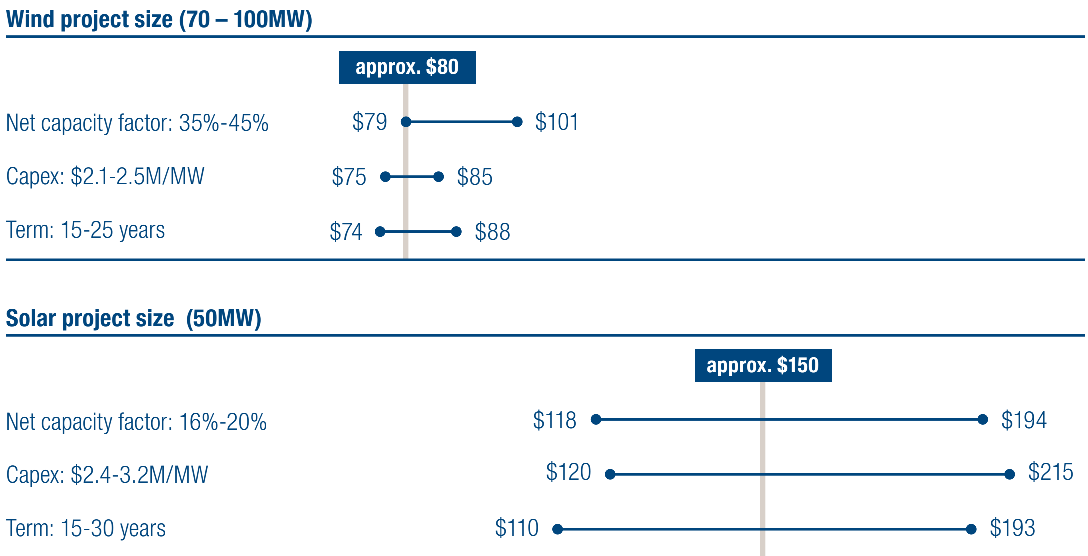
The levelized cost for utility-scale solar projects is estimated to range from $110/MWh to $215/MWh, with an expected value of approximately $150/MWh.

Estimates are based on a sample of cost and financing assumptions from relevant projects in the Canadian renewables market today. Cost ranges were developed by applying sensitivity analysis to the net capacity factor[16], capital expenditure and contract term. A more detailed summary of the impact on levelized costs of each of these sensitivities can be found below. Additional sensitivities were also carried out on foreign exchange and the project rate of return.

[15] A levelized cost is the estimated $/MWh required for a particular source of electricity generation to recover the cost (including return on capital) of that source of electricity generation over its expected life based on an assumed capacity factor. It is used to compare the cost of different generation technologies.

[16] The net capacity factor of a generation facility is the ratio of its actual output over a period of time to its potential output if it were possible for the facility to operate at full nameplate capacity continuously over the same period of time.

FIGURE 1: Levelized costs of solar and wind projects



A renewable investor/developer will expect to recover the cost of its renewable project (i.e. $80/MWh or $150/MWh) over the life of the agreement (which the AESO is recommending be set at 20 years). Costs are expected to be recovered from two main sources:

- The Alberta pool price at the time the project is producing electricity; and
- The support that is provided as a result of being a winning bidder in the Program[17].

This would be the case regardless of the payment mechanism selected (i.e. Fixed or Indexed REC). The choice of payment mechanism will, however, affect how an investor/developer views overall project risk, and therefore how it will calculate the level of support that it requires. This can impact the overall cost of the Program to the GoA.

4.6.2 Impact of payment mechanism on cost

A key driver to minimizing costs as part of a competitive process is to maximize the number of competitors, which in turn increases competitive pressures on bid pricing.

A feature of the renewables market is that a large proportion of investors/developers rely upon project financing to fund their projects. Therefore, the AESO considered potential payment mechanisms that provide opportunities for investors/developers to propose different financial structures, including project finance capital structures, on competitive terms.

Key to attracting project finance on competitive terms (i.e. relative to balance sheet financing) is to ensure that project risks are allocated to the party (or parties) best able to manage them. Risks such as construction cost risk are best managed by the investor/developer – an approach that is well established in project finance markets. However, based on stakeholder feedback it is clear that investors/developers and lenders feel strongly that the risk associated with the current pool price uncertainty cannot be managed, mitigated or effectively forecast, and is best retained by the public authority (i.e. the GoA).

[17] There is very little liquidity in Alberta's wholesale electricity market today, with limited or no opportunity to find parties who will contract for the large volume of renewable attributes and/or energy that will be generated from the Program. Additionally, offtake agreements usually require an ability to provide electricity 24/7. Renewable electricity generation is intermittent and cannot meet the 24/7 requirement.

If a payment mechanism is adopted that exposes investors/developers to movements in pool price, then, given the price uncertainty prevailing today, it is anticipated that competition will be reduced and that significant risk premiums are likely to be included in bid prices by those who do participate.

As described above, an investor/developer's revenue is mainly derived from both the pool price and support payments. However, under the Fixed REC mechanism the investor/developer is ultimately exposed to the consequences of movements in the pool price. Comparatively, under an Indexed REC mechanism the investor/developer is not exposed to movements in pool price; price volatility is absorbed by the GoA. The impact of price uncertainty will be more strongly reflected in a Fixed REC mechanism and the levels of support will include potentially significant risk premiums to reflect the fact that the investor/developer bears the risk of pool price uncertainty.

This risk premium will likely be modelled by investors/developers as a discount to their assumed pool price for the duration of the agreement term. The higher the pool price uncertainty experienced by investors/developers, the higher the discount that will be applied to the pool price.

For example, assuming a levelized cost of $80/MWh, if Fixed REC bidders assume a pool price for wind of $40/MWh, then they would need to receive a support payment of $40/MWh. However, if bidders discount the pool price for wind (e.g. to $20/MWh) because of their inability to accurately forecast pool price, they would bid a higher support payment of $60/MWh.

Alternatively, under an Indexed REC mechanism, the strike price would be $80/MWh regardless of a bidder's assumption with respect to pool price, and the public authority (in this case, the GoA) would bear the consequences of movements in pool price.

Furthermore, feedback from stakeholders and capital markets indicates that when sizing project debt under a Fixed REC mechanism, a pool price of near to zero may be assumed because they do not feel they can forecast pool price given current uncertainties – thereby passing all price risk to the GoA. The same feedback suggests that investors are resistant (and in many cases unwilling) to assume that risk in today's electricity market.

Appendix B provides the results of an analysis that estimates the potential impact on Program costs of premiums relating to pool price uncertainty. As an illustrative extract from that analysis, it is estimated that over the 20-year term of a 300 MW wind procurement, if investors/developers apply a 25 per cent discount to base pool price forecasts, then the cost of the Fixed REC support could exceed the cost of the Indexed REC support by approximately $261 million.

The analysis shows that even relatively modest investor risk-adjusted discounts to pool prices can result in the addition of significant costs to the Program. The choice of payment mechanism, particularly during times of high price uncertainty, can therefore have a significant and prolonged effect on Program cost.

A further consequence of a Fixed REC mechanism is that any additional revenue that accrues from higher-than-expected pool price (i.e. the pool price that was assumed when they determined their bid price), is retained by the investor/developer to the detriment of consumers. Under an Indexed REC mechanism, a higher pool price offsets the support payable by the GoA to the benefit of Albertans. As illustrated in Appendix B, the Indexed REC minimizes the cost of support for renewables under current market conditions. Given that the Program is to be funded by the carbon levy, it also minimizes funds required from the GoA[18].

[18] www.alberta.ca/budget-revenue.cfm

5.0 The first competition

5.0 The first competition

5.1 KEY HIGHLIGHTS

The AESO recommends the following objectives for the first competition:

- Projects are to be in service in 2019 as directed by the GoA. In order to achieve this objective, the AESO has determined that the first competition should be launched by the end of 2016;
- The design features of the first competition must position it for success; and
- The competition must be fuel neutral.

The objectives for the first competition drive a number of other recommended key features for this competition, including:

- Projects must leverage the existing transmission and distribution infrastructure;
- The exclusion of additional RFQ criteria other than financial and technical considerations[19] (Section 4.4 identifies the RFQ criteria that will be used for the first competition); and
- The use of an Indexed REC payment mechanism.

> Based on the AESO's analysis, a 2019 in-service date is likely achievable for a number of renewable projects, representing in excess of 1,500 MW of generation.

[19] This competition will be best positioned for success if it is straightforward and efficient and focuses on delivery of the largest quantity of renewables that may be procured within the available GoA funding. This competition is not intended to advance additional objectives, such as socio-economic ones (e.g. fuel carve-outs or rural development benefits) which would create more complexity in the process, especially as it relates to bid preparation, evaluation and the timing associated with each of those activities.

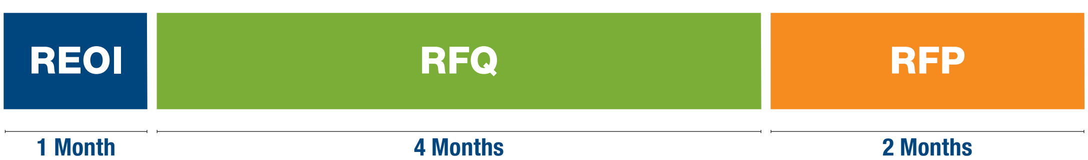
5.2 OVERVIEW

TABLE 4: Key features of the first competition

Key features	Description
Competition stages	▪ Will include REOI, RFQ and RFP ▪ Competition to launch by end of 2016
Primary objectives	▪ Projects energize in 2019
Fuel type	▪ Fuel neutral
Eligibility	▪ Meets renewable definition ▪ New and expanded projects only ▪ Projects must be located in Alberta
Eligible size	▪ Utility scale ≥5 MW
Volume	▪ 200 MW – 400 MW
Contract term	▪ 20 years
Affordability threshold	▪ Private cap that AESO and GoA may use to determine accepted volumes and next steps
Connection to the transmission or distribution system	▪ Must demonstrate ability to connect to existing transmission or distribution facilities ▪ Connection access to the transmission system may have to be prioritized in favour of winning bidders of the first competition
Payment mechanism	▪ Indexed REC

5.3 STAGES AND TIMELINES FOR THE FIRST COMPETITION

As illustrated below, the AESO recommends that the first competition will include all three stages. While discretionary, the REOI stage will have important benefits for the first competition. It is expected to create awareness and provide early feedback to the AESO and the GoA regarding the potential level of interest in the competition as well as the parties that may participate. These signals are likely to be indicators of the success of the first competition.



The proposed timeline of approximately seven months to implement the first competition is compressed relative to the implementation timeline of renewable competitions in other jurisdictions (i.e. usually 12 months for the first competition of a new program). The first competition must be kept simple given the aggressiveness of the timelines. The main driver for this is to maximize the number of bidders who can participate in the first competition while providing winning bidders with sufficient time to develop and construct their projects and achieve a 2019 in-service date.

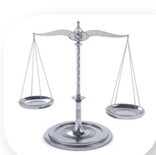
5.4 POTENTIAL PROJECTS TO PARTICIPATE IN THE FIRST COMPETITION

On average, depending on the renewable resource, it may take a developer 2–6 years to develop, permit and energize a project. Appendix C provides an illustration of how these stages may apply in the context of a wind generation project.

Based on the AESO's analysis, a 2019 in-service date is likely achievable for a number of renewable projects, representing in excess of 1,500 MW of generation. As there is sufficient transmission capacity in most of the renewable resource regions today, the AESO does not anticipate that any bulk transmission system expansions will be required for the first competition or for the next several competitions. As well, discussions between the AESO and distribution facility owners have indicated that there may be significant developer interest with respect to connecting wind and solar renewable generation projects to the distribution system.

While there appears to be a number of projects that may be able to compete, several factors unrelated to connecting to the transmission system may affect the timing and ultimately the energization of projects. These include receiving environmental and regulatory approvals as well as securing debt financing. Given the timing of the first competition, there may not be an opportunity to streamline the environmental and regulatory-related processes and approvals; the timing associated with these processes may continue to be a constraint and may impact a project's ability to achieve the 2019 target in-service date.

The AESO expects healthy competition will drive bid pricing (i.e. the costs of GoA support) down to the benefit of Albertans. However, the payment mechanism chosen may significantly impact the level of participation in the first competition.



When considered from a holistic perspective, the Indexed REC is the best mechanism to meet the objectives of the Program, generic competitive process and the first competition.

5.5 PAYMENT MECHANISM

The AESO recommends the use of an Indexed REC as the payment mechanism for the first competition.

As described in Table 2, the benefits of using an Indexed REC are as follows:

- It is expected to minimize the cost of the first competition over the term of the agreement because bidders are not being asked to assume the current pool price risk that arises from the transition to a low-carbon future. Therefore, risk premiums that would otherwise be included in bid pricing will likely be avoided;
- It is expected to best position the competition for success, given it is likely to maximize the number of competitors, putting significant downward pressure on bid prices;
- It is not expected to get out of step with the pool price as the support payment has an automatic adjuster built within it such that when pool price rises, the value of the support payments fall. Should the pool price rise above a bidder's strike price, winning bidders will pay the GoA for the difference;
- It is not expected to fundamentally alter the current wholesale electricity market;
- It aligns with the results of the AESO's engagement activities, wherein investors/developers and lenders repeatedly highlighted the need for revenue certainty to attract competitors, minimize financing costs and generate a wider range of pricing; and
- It is expected to minimize Program costs to Albertans and avoid windfall gains for investors/developers.

When considered from a holistic perspective, the Indexed REC is currently best suited to meet the objectives of the Program, generic competitive process and the first competition.

6.0 Due diligence and engagement

6.0 Due diligence and engagement

To assist the AESO with the development of its recommendations, a number of research and engagement activities have been completed. These activities were undertaken to gather intelligence with respect to how renewable incentive programs have been approached in other jurisdictions as well as insights into how such a program might be best implemented in Alberta.

6.1 JURISDICTIONAL REVIEW

In February 2016, the AESO retained London Economics International LLC (LEI) to conduct a review of other jurisdictions so that the AESO could better understand how they approached their renewable incentive programs (e.g. did they procure renewable energy in the form of a bundled product, or solely renewable attributes). More specifically, LEI was asked to:

(a) Identify and summarize the types of programs that have been used to increase the quantity of renewable electricity generation in various North American and European jurisdictions, in addition to the relevant context for such programs (i.e. whether other objectives in addition to increasing renewable electricity generation were being advanced) and whether such programs were premised on the provision of full or partial financial support; and

(b) Identify a subset of jurisdictions that exemplify the types of programs identified above that were most applicable to Alberta, and compare and contrast these jurisdictions and programs vis-a-vis the Alberta context with a focus on:

- Objectives that were or are being pursued in these jurisdictions, including whether any program linked its targets for renewable electricity generation with the retirement of a coal fleet; and
- Key defining market features of these jurisdictions (e.g. the nature of the fleet, consumption characteristics of residential, commercial and industrial sectors), including the design of each of the electricity markets.

LEI prepared an assessment of how the centralized procurement of renewable energy was undertaken in the following five jurisdictions: Australia, California, New York, Ontario and the United Kingdom. While the policy and market environments of each of these jurisdictions are distinguishable from that of Alberta, the review of the approaches to the design and implementation of competitive procurement processes in each of these jurisdictions helped to identify trends and best practices common to most programs and provided insight regarding the potential implications for Alberta should such practices be adopted. A brief summary of LEI's findings is set out below[20].

[20] The LEI final report is provided in Appendix D.

There were a number of similar learnings across all five jurisdictions that were leveraged and incorporated into the design of Alberta's proposed Program in order to make it more robust.

As expected, the experiences of each jurisdiction varied largely due to their unique market structures and policy objectives. However, a number of common themes were identified:

- Most jurisdictions had ambitious renewable targets;
- All jurisdictions had competitions that were oversubscribed;
- Competitive processes, rather than administrative processes, were typically used;
- Revenue certainty for project developers could be achieved[21] (e.g. through capacity markets or the aggregation of other revenue streams via tax credits, subsidies, bilateral contracts, etc.); and
- Many jurisdictions have refined their approaches to procuring renewable energy in order to reflect lessons learned and/or to advance new objectives.

There were also a number of similar learnings across all five jurisdictions that were leveraged and incorporated into the design of Alberta's proposed Program in order to make it more robust. For example, the experiences in the other jurisdictions suggest the process should:

- Be clear and transparent about key aspects of the competition (e.g. goals for the competition, product definition, term of the contractual arrangement, technologies eligible to compete, etc.);
- Be designed to vet bidders to ensure that only serious bids are submitted (e.g. by requiring bid deposit and contract security);
- Minimize opportunities for non-competitive behavior;
- Use transparent and objective systems for bid evaluation to the extent possible;
- Have third party oversight during the process (e.g. use a Fairness Advisor);
- Set realistic timeframes for the competitive process (e.g. 12 months for a first competition was noted as reasonable); and
- Minimize the integration of other policy goals as part of the competitive process, given the complexities associated with the evaluation and ongoing monitoring of bidders.

[21] Revenue certainty has become a key feature of the renewable electricity generation industry as it has developed over time.

In addition to the above, other notable observations worth highlighting include the following:

- None of the jurisdictions reviewed had an energy-only market similar to the one in Alberta[22]. Other jurisdictions are structured so that revenue certainty can be obtained by other means[23];
- The programs in New York and the United Kingdom procured environmental attributes; other jurisdictions procured bundled products (i.e. commodity plus environmental attributes);
- All programs except for Australia permitted different renewable technologies to compete against one another, or allowed for competition within a discrete class of renewable technology (Australia's program is designed to incent the development of solar generation); and
- The timeframe to run the competitive processes ranged from a very short period in the case of a mature program to approximately two years for competitive processes being undertaken for the first time.

The findings of the LEI report have influenced the design of the Program, the generic competitive process and the first competition.

6.2 RENEWABLE ELECTRICITY PROGRAM QUESTIONNAIRE

In addition to the points noted above, the LEI findings indicated stakeholder input was a key contributor to the development of a successful program. In order to receive input from the developer and investor communities, associations and other interested parties on the Program, the AESO commenced its engagement activities with a questionnaire[24] on March 3, 2016. The questions posed were high level in nature, and were intended to elicit a broad array of responses.

The following is a summary of the responses, posted to the AESO's website on May 5, 2016.

The questionnaire garnered responses from 138 respondents who self-identified as:

- 102 investors/developers;
- 11 associations and environmental groups; and
- 25 stakeholders who identified as "others."

[22] Alberta and Texas are two jurisdictions that are often compared given they are energy-only markets. However, it is noteworthy that in Texas the growth in renewable generation has been attributed to a combination of the availability of government tax credits, significant transmission development (via the Competitive Renewable Energy Zones competitive process), and a Renewable Portfolio Standard target that creates load obligations and facilitates load side contracting.

[23] Examples of other mechanisms that may be used to create revenue certainty include leveraging tax and/or other types of research credits or subsidies, or entering into offtake agreements with third parties.

[24] Refer to Appendix E for a list of the questions posed in the questionnaire.

Responses relevant to Program currently under development included:

- Concerns about the current low pool price and the corresponding capital-intensive nature of renewable generation projects;
- Continuing uncertainties on a number of fronts, including political and policy uncertainties as the electricity industry moves through transition, lack of details with respect to the Program including timelines, plans, schedules and compensation associated with the phase-out of the coal fleet, the potential for change in the current market structure and the possibility that imports may be given preferential treatment;
- The complexity, timeliness of regulatory approvals and a concern that regulatory agencies are not appropriately resourced to accommodate the increased volume of work associated with various aspects of the transition;
- Whether and how curtailment rules could be revised;
- The length of time to move through the AESO's connection process; and
- Inadequate transmission capacity to meet GoA's renewable targets.

To resolve the issues identified above, respondents highlighted the following:

- Provide some form of financial support to create revenue certainty for renewable projects. Recommended options included capped or uncapped renewable energy credits (RECs), Contract for Differences (CFD), Power Purchase Agreements (PPAs), Feed-in-Tariffs (FIT) or some form of GoA financial backing;
- Provide clarity on whether the current market structure would continue or be redesigned;
- Provide details on the Program including the schedule (e.g. MW per year);
- Consider allowing renewable electricity generation projects to develop on Crown lands; and
- Other recommendations included matching the agreement term for the renewable electricity generation project to the life of the asset, creating competitions for specific fuels (e.g. fuel carve-outs), providing clarity on curtailment policies and providing information with respect to transmission capacity.

Responses garnered from the Renewable Electricity Program questionnaire were important for confirming the existence and relevance of issues the AESO had already identified in the course of its development work, and helping the AESO better understand parties' most significant concerns with respect to the competitions.

6.3 TARGETED ONE-ON-ONE MEETINGS

The responses to the Renewable Electricity Program questionnaire helped to inform the next phase of the AESO's engagement, which was comprised of a series of one-on-one meetings. The stakeholders targeted for these meetings included parties who provided responses to the questionnaire from which the AESO required further clarification and members of the lender (capital markets) community.

While the AESO's meetings with respondents to the questionnaire were tailored to the responses specific to those parties, the meetings conducted by KPMG with members of the lender community[25] focused on a discussion of the following:

- The challenges to financing renewable projects that may be incurred in Alberta;
- How the structure of commercial terms may impact the cost and availability of financing for renewable projects; and
- The change in capital market sentiment on financing renewable electricity projects that have merchant price risk exposure[26] generally, and specifically in Alberta, given its energy-only market.

Feedback received from these interviews echoed many of the same concerns raised by respondents to the Renewable Electricity Program questionnaire, including concerns regarding the uncertainty of the future supply mix and market design changes, uncertainty around the coal retirement schedule and potential policy instability.

In general, lenders indicated their preference to invest in projects with long-term contracted cash flows. Therefore, the current uncertainty in Alberta and volatility in the pool price make it very difficult to finance projects in an energy-only market. While renewable lenders are willing to take some operating and resource risk (e.g. for wind or solar projects) there is a high degree of discomfort in taking price risks or financing merchant projects.

Regarding the payment mechanism, lenders believe that project economics are not workable at the current pool price with a Fixed REC of $35/MWh. All lenders who provided a response preferred an Indexed REC approach as the best way to achieve an effective cost of financing and capital structure.

Lenders expressed a desire to better understand the Program's agreement provisions and the counterparty (i.e. the AESO) to the long-term agreements, including such party's creditworthiness. How the AESO intends to manage transmission congestion risk was also of great interest, as this risk has had a high profile in Ontario and Texas due to transmission congestion. Transmission congestion in Alberta is likely to deter lenders from participating if they believe congestion and subsequent curtailment cannot be forecasted and is likely to be of significant duration and/or frequency. In addition, lenders also expressed concerns about minimum availability thresholds and minimum production hurdles that may be imposed on renewable generators.

Finally, concerns were raised about the length of time required for participants in the Program to achieve permits and approvals. It was suggested that the relevant regulatory processes should be carefully reviewed and streamlined so as to avoid any unnecessary delays[27].

[25] The AESO, through KPMG, reached out to domestic and international banks and large Canadian insurance companies.

[26] Merchant risk exposure is exposure to revenue variability that is inherent in Alberta's real-time power market.

[27] In corporate finance, a company's balance sheet is used as collateral in case of a default under the loan agreement. Corporate finance lenders will not necessarily look at the type of capital investment that the debt will be used to fund. In project finance, repayment of the loan is tied to project revenues – there is limited recourse to the project investors. Project finance lenders therefore look very carefully at the type of investment and the likelihood of potential project default.

Given the investor/developer/lender feedback described above, the AESO sought advice from its capital markets advisor JCRA Financial LLC (JCRA) as to whether financial concerns and dampened developer interest raised by stakeholders were specific to the Alberta market, or whether they arose because of circumstances in global financial markets. Specifically, the AESO asked JCRA to consider the following:

- Whether the price uncertainty observed in Alberta's energy-only market today would dissuade new investment and/or present challenges when it comes to financing new capital expenditure (both in terms of availability of finance and cost);
- Generally, when raising debt financing for projects that carry merchant price risk, are finance markets today more or less conservative than in previous years (in terms of both project and corporate finance); and
- In previous years, projects carrying merchant price risk have been readily financeable in Alberta using corporate finance; would these same projects be similarly financeable today if the increased price uncertainty evident in the market was absent.

JCRA concluded that price uncertainty in Alberta is an important issue when developers look to debt finance their projects. Without price certainty, projects will have difficulty raising debt finance and more expensive equity financing will be required, which would result in very expensive capital structures.

With respect to the global financial market, JCRA noted that immediately following the 2008 financial crisis, lenders required long-dated power purchase agreements that provided revenue certainty to mitigate against price and volume risk. However, with the passage of time, and as financial markets have recovered and become more healthy, investors and lenders have been more willing to take on risk, especially if hedges can be put in place. JCRA concluded by stating that debt capital markets would be receptive to projects carrying merchant risk if there was more price certainty in the market. A copy of JCRA's letter is contained in Appendix F.

6.4 MARKET SOUNDING BY MORRISON PARK ADVISORS

In addition to the fulsome assessment and implementation strategy of the coal emissions phase-out and the Program, the AESO is undertaking a detailed assessment of the ability of the current energy market structure to continue to provide the necessary investment and dispatch signals during and after the transition to a greener grid. As part of this work, the AESO retained Morrison Park Advisors (MPA) to conduct a series of one-on-one interviews with developers/owners/operators of non-renewable electricity generation facilities, as well as capital market participants, to gauge their level of interest in investing in non-renewables in Alberta in the foreseeable future. MPA was asked to gather perspectives on barriers to investment and potential solutions to these barriers given recent policy decisions in Alberta, and to determine their investment appetite after the resolution of key policy issues. MPA has provided its preliminary findings to the AESO and a final report will be issued at the end of May 2016. Notwithstanding that the focus of these interviews was investment in non-renewable projects, interviewee observations about the level of uncertainty in Alberta, at present and in the market generally, proved to be very informative regarding the potential appetite for investment in renewable projects.

The initial results of the interviews suggest that there has been a significant erosion of the support for investing in the energy-only markets in Alberta (and elsewhere) given market and policy uncertainty is undermining confidence. Uncertainty is being created by a range of factors including declining oil prices, details of the plan to phase out coal emissions, and implementation details of the Program. Climate change initiatives have been the cause of uncertainty across the globe as other jurisdictions have shifted away from traditional thinking and how risk is allocated. Incumbent electricity generators and other market participants appeared to be severely stressed by current uncertainties; their views are in stark contrast to those expressed during similar interviews undertaken in 2012[28]. Project financing continues to be unavailable to Alberta projects while balance sheet financing investment has been eroded in Alberta. Several capital market interviewees commented on the changing perceptions and cost of risk and their unwillingness to place any value on prospective merchant revenue, even as part of balanced portfolios. Merchant projects with low revenue certainty are therefore considered unattractive and non-financeable.

MPA's overall observation is that capital markets are broader and deeper than they were in 2012 and therefore there are enormous pools of capital available for very specific types of investment. Conversely, MPA believes that these pools are absolutely unavailable for other investments that sit outside these specific types. This is referred to as the "binary" effect, which is further complicated by the valuations of risk-reward that are also bifurcated into classes (i.e. if a project is too risky, capital will not be made available).

There are early, strong signals which suggest the Alberta market is currently not attractive enough to incumbent and new participants to support investment in non-renewables. The nature of these conclusions align very closely with the feedback the AESO has received around investment in renewables as part of its questionnaire and as part of further diligence conducted by KPMG and JCRA, indicating a broad negative sentiment to merchant development without revenue certainty.

[28] In 2012 the Market Surveillance Administrator retained MPA to conduct a similar market sounding. Many of the same parties participated in both sets of interviews.

6.5 ADDITIONAL AND ONGOING DUE DILIGENCE

In conjunction with the above activities, the AESO has also been advancing other significant work internally, some of which has already been incorporated into the structure and content of each of the competitive process stages. Much of this work, while very relevant to the first competition, will become even more important to informing subsequent competitions in the Program. The work is in relation to a wide range of matters, including:

- An in-depth review of the terms of the procurement documents and forms of agreements in use by other jurisdictions[29] in order to have a comprehensive understanding of the alternate approaches that have been taken, including how RFQ criteria have been structured, what rights the central authorities running the processes have reserved for themselves, how risk allocations have been achieved, etc.;
- A review of the ability of the AESO to manage and operate the transmission system in a reliable manner as the volume of renewables on the AIES increases;
- A review of the current process for system access, including an assessment of the AESO Connection Process, the requirements that must be met at each of the various stages and the timelines for advancing through the process;
- The level of visibility the AESO currently has with respect to the distribution system, and the processes in place for connecting generation to the distribution system;
- A review of the existing transmission capacity on the AIES, and the plans for future transmission builds; and
- A review of ISO rules and technical standards for generating facilities.

[29] The procurement and contract documentation from Ontario (Canadian jurisdiction, procure large-scale bundled products and use a contract for differences payment mechanism), British Columbia (Canadian jurisdiction, use a Feed-in-Tariff payment mechanism and include examples of risk allocations), the United Kingdom (procure renewable attributes only and use a contract for differences payment mechanism), New York (procure renewable attributes only and use a Fixed REC payment mechanism) and California (procure a bundled product and use a Fixed REC payment mechanism) continue to be reviewed. The documentation from these jurisdictions is most informative as it represents the approach taken by Canadian jurisdictions, in the case of Ontario and British Columbia, and how risk allocations have been addressed with an Indexed REC (i.e. contract for differences) payment mechanism.

7.0 Remaining milestones for 2016

7.0 Remaining milestones for 2016

TABLE 5: Timeline of the AESO's key activities planned for the remainder of 2016

Activity	Date
Deliver Renewable Electricity Program Recommendations to GoA	May 31, 2016
Engage with distribution facility owners[30]	June – July 2016
Prepare procurement documents and commercial agreements	June – September 2016
Seek confirmation from GoA regarding flow of funds	September 2016
Engage with industry regarding key commercial terms	September – November 2016
Seek confirmation from GoA regarding key commercial terms	November 2016
Issue REOI for the first competition	December 2016

Given the number of significant milestones that must be achieved over the coming months, the target launch date of the first competition in December 2016 is an aggressive one. The AESO will need to retain flexibility with respect to the schedule so that it may advance work earlier than planned. Given the compressed schedule for 2016, the AESO is continuing to advance its work on the development of the Program, in concert with AE, as per the recommendations contained within this document. Time will be of the essence with respect to all activities that will be required to be undertaken by either the AESO or AE. What follows are highlights of the activities the AESO has identified as critical path for success of the Program and the first competition in particular.

7.1 LEGISLATIVE CHANGES

At the time the AESO was formally tasked with leading the development of the Program, a review was undertaken to assess what amendments to legislation might be required in order to ensure that the AESO had the requisite authority to undertake this work and that once developed, the Program could be implemented pursuant to the current legislative regime. The AESO has been providing frequent updates to AE regarding the advancement of this work, and has advised that a broadening of its mandate is required with respect to the Program. A number of amendments to the *Electric Utilities Act* (EUA) are required given the current provisions of the EUA do not support incenting renewable generation, nor the AESO's authority to design and implement the Program.

AE made the request for the AESO to identify what it believes to be the necessary suite of legislative amendments. These proposed legislative amendments were submitted to AE on May 16, 2016. The AESO believes that finalizing these amendments at the 2016 fall session of the legislature is a critical path activity in order to meet the timing of a December 2016 launch for the first competition.

[30] Given there will likely be a number of projects that propose to connect to the distribution system, it will be important for the AESO to understand how the Program may impact this system and the distribution facility owners in the long term.

7.1.1 Proposed amendments

When developing the proposed amendments, the AESO was mindful of the fact the EUA supports the current market framework and principles (i.e. fair, efficient, open and competitive market for the exchange of electricity) and that a balance must be achieved between maintaining investor interest and confidence in this framework, and ensuring the AESO can develop and implement the Program in a timely and efficient manner with minimal legal or regulatory risk. This balance was articulated in the following four principles, which guided the nature of the proposed amendments.

Principle 1	The AESO must have explicit authority to develop and implement the Program.
Principle 2	Attempt to minimize the risk of legal and regulatory challenges to the development and implementation of the Program.
Principle 3	Be mindful of how the Program will be implemented within the current market structure and minimize changes to the legislative framework to maintain investor interest and confidence.
Principle 4	Encourage efficient and timely processes and oversight in order to reduce Program-related regulatory burden on interested parties and regulatory agencies.

While a suite of amendments have been proposed for the Program based on the principles above, the amendments most critical to the immediate success of the Program include:

- Expanding the purposes of the EUA (Section 5) to include the incenting of renewable generation; and
- Adding the design and implementation of the Program as new duties of the ISO (Section 17), whereby:
  - The AESO's authority to implement the Program is pursuant to Ministerial approval; and
  - Certain features and restrictions of the Program that may otherwise conflict with the EUA are permissible.

The AESO has also informed AE that other amendments may be required as the Program is further developed (e.g. to support the flow of funds from the GoA to the AESO) or to support the advancement of other initiatives (such as the coal emissions phase-out).

The AESO notes that a delay in legislative change beyond the fall sitting of the legislature would have a significant, adverse impact on the AESO's ability to meet the target launch for the first competition in December 2016.

7.2 ONGOING ENGAGEMENT

As indicated in Section 6.2 of this document, the AESO launched its stakeholder engagement with the Renewable Electricity Program questionnaire, and has continued to seek stakeholder input with respect to various aspects of the overall Program and the first competition. The AESO has expressly committed to ongoing engagement with industry with respect to the Program, the first competition and all subsequent competitions moving forward. Similar to its experience with the Competitive Process for transmission, the AESO views consultation with stakeholders to be both a necessary and fundamental part of the development process, especially as it pertains to the development of the terms of the procurement documents and provisions of the support agreements that winners of the competition will be required to execute.

The preparation of both the procurement documents and the support agreements is currently underway; however, given the significance of the task it is anticipated that the AESO will not be in a position to release drafts of the procurement documents and/or agreements to stakeholders for review and comment until the fall of 2016.

The AESO notes that the outcome of discussions between itself and the GoA in early 2016 resulted in a decision by the GoA that it would manage and coordinate engagement with Indigenous peoples[31], landowners and municipalities. The focus of the AESO's engagement efforts would therefore be with the investor and developer communities as well as other interested parties[32]. This delineation has and will continue to allow the AESO to concentrate on the types of feedback necessary to further develop key elements of the Program, such as the procurement documents and long-term agreements. It also enables the GoA to coordinate its engagement for the Program with its broader CLP engagement activities.

The AESO anticipates that targeted meetings with various stakeholders are likely to continue, including broad consultation through in-person meetings and written submissions in order to solicit specific feedback on items such as contractual provisions.

[31] The AESO recognizes that the legal duty to consult Indigenous Peoples rests with the GoA. The AESO will continue to support the GoA moving forward with respect to issues or concerns as the Program develops.

[32] It is the AESO's understanding that a number of potential participants in the Program have plans to connect to the distribution system, and therefore the AESO intends to engage directly with distribution facility owners.

Ongoing engagement with AE will continue to be of paramount importance as the AESO prepares to launch the first competition. The AESO will be seeking timely input, and in some cases direction from the GoA, on recommendations that will be forthcoming, including:

- How the funds needed to pay the winners of the competitions will flow between the GoA and the AESO[33];
- The affordability cap that will apply to the first competition; and
- The key commercial terms of the final form of support agreement for the first competition.

7.3 ONGOING GOVERNANCE FOR THE PROGRAM

There will be a need to implement an ongoing governance mechanism between the AESO and the GoA to address two aspects of the Program. The first relates to the AESO providing updates to the GoA about the overall program, such as the results of any given competition, advancement towards the overall and any interim targets, and the status (or recommendations if applicable) regarding the operations and reliability of the AIES.

The second aspect of the Program for which an ongoing governance structure is required relates to decisions that will be sought regarding the key features for each individual competition. The AESO proposes to prepare a unique recommendation for each competition, in a similar form as that presented for the first competition, to request a decision from the GoA on the objectives, selection criteria, payment mechanism and earmarked funding for each procurement.

It is the AESO's understanding that AE is currently preparing a proposed governance model.

7.3.1 Subsequent competitions

The objectives for subsequent competitions will rely on the principles of the generic competitive process and the overall Program. However, the key features of each competition may include other GoA objectives (such as advancement of socio-economic objectives) or may reflect other considerations recommended by the AESO (e.g. relating to the management of generation supply and the appropriate volume of renewable attributes to be procured as the coal fleet retires).

As the AESO gives further consideration to future competitions it will need to be mindful of when other jurisdictions are advancing their renewable generation programs and the characteristics of such programs. Notwithstanding the opportunities that may exist with these types of programs worldwide, even in Canada, the provinces of Saskatchewan, Manitoba and Ontario are all likely to be competing with Alberta for investment.

The GoA has expressed its desire for the AESO to both manage the Program in concert with the retirement of the coal fleet, and be mindful of the structure of the electricity market. Therefore, the AESO recommends that the objectives and key features of each competition moving forward be tested against each of these criteria.

[33] Project finance lenders are very likely to require greater certainty with respect to the ISO's source of the funds and payment mechanisms that will be used to make payments under the Program. This is best provided in the form of a statutory payment obligation or government guarantee.

Appendix A

Alberta

Energy
Office of the Deputy Minister
Petroleum Plaza, NT, Floor 8
9945 - 108 Street
Edmonton, Alberta T5K 2G6
Canada
Telephone: 780-415-8434
Fax: 780-427-7737
Email: grant.sprague@gov.ab.ca
www.alberta.ca

January 26, 2016

Mr. David Erickson
President and Chief Executive Officer
Alberta Electric System Operator
2500, 330-5 Avenue SW
Calgary, Alberta T2P 0L4

Dear Mr. Erickson:

This letter will serve to confirm that the Alberta Electric System Operator has been tasked to develop and implement a plan to bring on new renewable electricity generation capacity, in accordance with Government direction, to the grid by 2030 while keeping the costs of doing so as low as possible through a competitive process, such as an auction. This process must be carefully managed and operate in concert with the retirement of current coal generating units.

You are asked to prepare a plan for review and consideration by government no later than May 2016.

I also confirm that the Government of Alberta has not chosen to fundamentally alter the current wholesale electricity market structure.

Please continue to work closely with Alberta Energy.

Sincerely,

Grant D. Sprague, Q.C.
Deputy Minister

Appendix B

Potential Impact of Pool Price Uncertainty on Program Costs

Introduction

The AESO sought to determine the potential impact on Program costs that would result from investors/developers discounting pool price projections in order to mitigate the risk to revenue of price uncertainty.

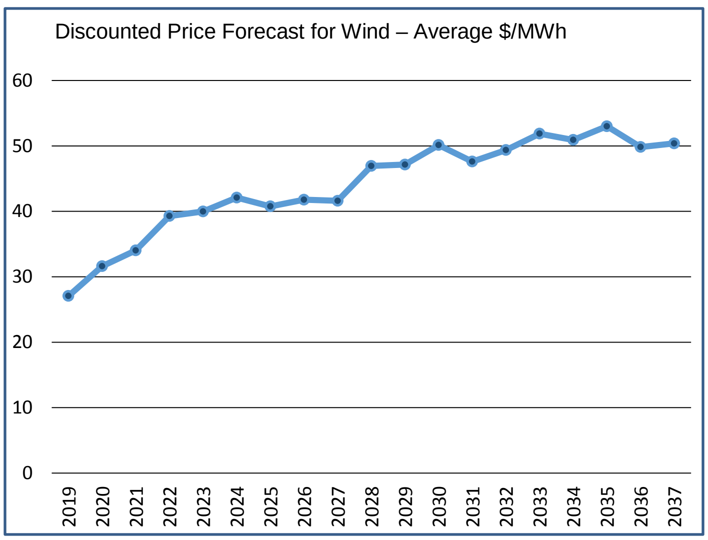
The analysis first estimates the Indexed REC strike price based on the levelized cost analysis described in Section 4.6.1. The estimated levelized cost includes all project costs and the value of the Indexed REC is therefore the same.

Second, an equivalent Fixed REC is estimated based on various levels of discount to the base pool price forecast. The Fixed REC is calculated such that (1) the total of the assumed energy revenue (based on discounted pool price) plus the revenue from the Fixed REC is equal to (2) the true energy cost estimate (based on undiscounted price) plus the net Indexed REC cost (i.e. as the assumed energy revenues fall, the Fixed REC increases to compensate).

Assumptions

The analysis is based on a number of assumptions:

- Technology: Wind
- Levelized cost: $80/MWh
- Procurement volume: 300 MW
- Capacity factor: 45%[1]
- Agreement term: 20 years
- REC inflation: None
- Price Forecast: Representative pool price forecast



[1] While capacity factors historically have been approximately 35%, it is assumed that technological advances will increase capacity factors to 45%.

2500, 330-5th Avenue SW, Calgary, Alberta T2P 0L4 Phone: 403-539-2450 Fax: 403-539-2949
www.aeso.ca www.poweringalberta.com

Results

Total estimated support costs over the life of a 300 MW competition are shown below for both a Fixed REC and Indexed REC.

	Fixed REC			Indexed REC			
Price Forecast Discount Applied by Developer	Energy Revenue Assumed by Developer * $ million (1)	True Energy Cost ** $ million (2)	Fixed REC Cost $ million (3)	Energy Revenue Assumed by Developer *** $ million (4)	True Energy Cost ** $ million (5)	Net Indexed REC Cost $ million (6)	Delta $ million (3-6)
0%	$1,047	$1,047	$845	n/a	$1,047	$845	$0
25%	$786	$1,047	$1,106	n/a	$1,047	$845	$261
50%	$524	$1,047	$1,368	n/a	$1,047	$845	$523
75%	$262	$1,047	$1,630	n/a	$1,047	$845	$785
100%	$0	$1,047	$1,892	n/a	$1,047	$845	$1,047

* The energy revenue assumed by developers when calculating the support payment.

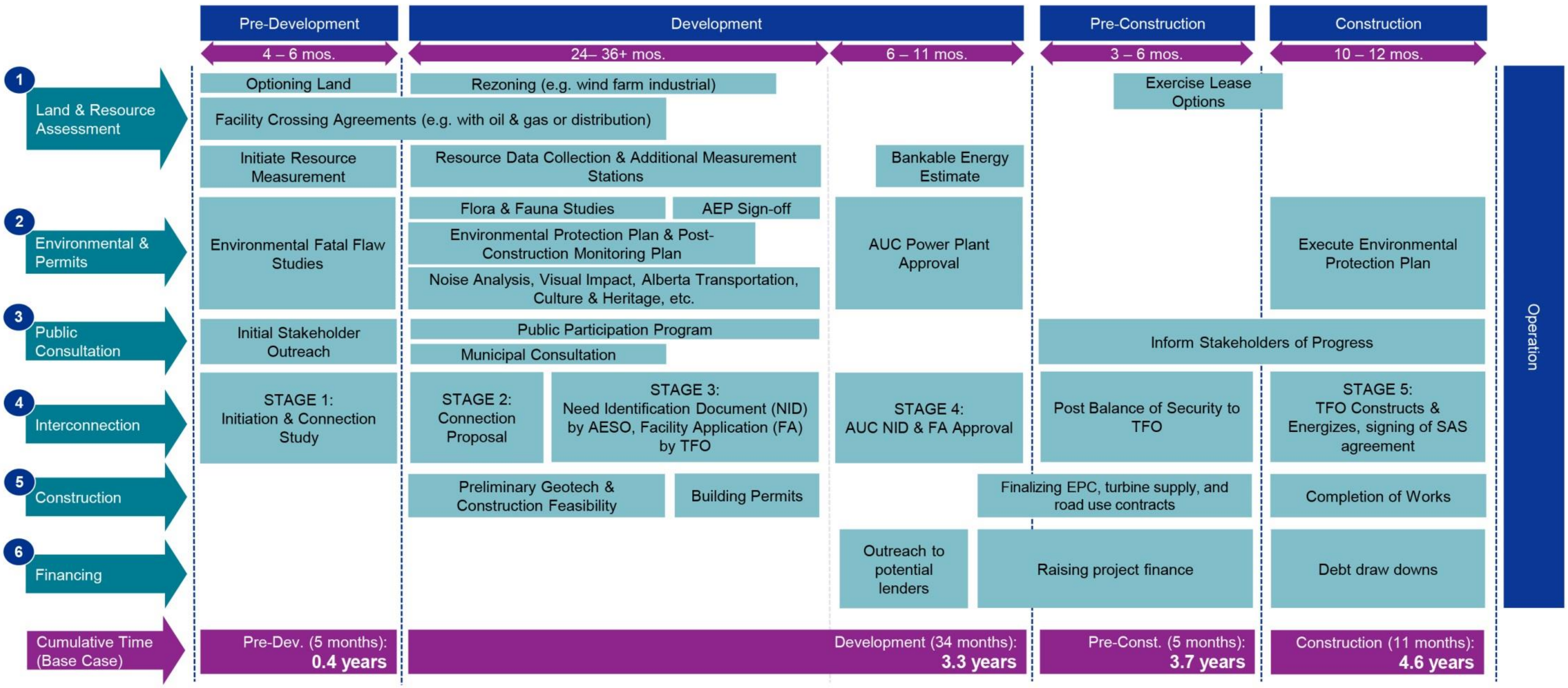
** Based on the AESO pool price forecast.

*** Developer takes no energy (i.e. pool price) revenue risk and therefore makes no energy revenue assumptions.

The cost of the Fixed REC increases as the assumed energy revenue decreases (i.e. as pool price expectations fall). As this effect only affects the Fixed REC structure, the support costs associated with the Fixed REC structure increase in line with pool price discount increases.

Appendix C

Wind Development Timeline



Confidential

2500, 330-5th Avenue SW, Calgary, Alberta T2P 0L4 Phone: 403-539-2450 Fax: 403-539-2949
www.aeso.ca www.poweringalberta.com

Appendix D

Case studies of jurisdictions with centralized procurement to encourage the development of renewable generation

Prepared for the Alberta Electric System Operator ("AESO") by London Economics International LLC ("LEI")

April 1, 2016

London Economics International LLC ("LEI") has prepared a detailed report assessing five approaches to the centralized competitive procurement of renewable energy as an input to the Alberta Electric System Operator's ("AESO") consideration of options for fulfilling the Alberta government's objective of increasing renewable energy. These five case studies include: Australia, California, New York, Ontario, and the United Kingdom. While the policy and market environments of these jurisdictions vary in many cases from the Alberta context, a comparison of their approaches to designing and implementing competitive procurement processes for renewables is useful for identifying trends and best practices. In this report we provide detailed case studies of these five procurement processes, summarize best practices in centralized competitive procurement processes, and discuss implications for how these might translate in the Alberta context.

Table of contents

Table of Figures

1 Acronyms

ACF	Average Capacity Factor
ACT	Australian Capital Territory
AEMO	Australian Energy Market Operator
AESO	Alberta Electric System Operator
ARENA	Australian Renewable Energy Agency
ARP	Advancing Renewables Programme
ASP	Administrative Strike Prices
CAISO	California Independent System Operator
CEC	California Energy Commission
CfD	Contract for Difference
CPUC	California Public Utilities Commission
CUE	California Utility Employees
DECC	Department of Energy & Climate Change
DRA	Division of Ratepayer Advocates
DWR	California Department of Water Resources
EOI	Expression of Interest
ETS	Emissions Trading System
EU	European Union
FIT	Feed in tariff
GSE	Gestori Servizi Energetici
IC	Independent Certifier
IE	Independent Evaluator
IESO	Independent Electricity System Operator
IOUs	Investor-Owned Utilities
IPP	Independent Power Producers
ITC	Investment Tax Credit
LADPW	Los Angeles Department of Water and Power
LCCC	Low Carbon Contracts Company
LCOE	Levelized Cost of Electricity
LEI	London Economics International LLC

LRET	Large-scale Renewable Energy Target
LRP	Large Renewable Procurement
LTEP	Ontario Long-Term Energy Plan
MACRS	Modified Accelerated Cost Recovery System
MASEN	Moroccan Agency for Solar Energy
MPR	Market Price Referent
NEM	National Electricity Market
NGET	National Grid Electricity Transmission
NPV	Net Present Value
NSP	Network Service Provider
NYISO	New York Independent System Operator
NYPSC	New York Public Service Commission
NYSERDA	New York State Energy Research and Development Authority
OPA	Ontario Power Authority
PG&E	Pacific Gas and Electric Company
POUs	Publicly Owned Municipal Utilities
PRG	Procurement Review Group
PTC	Production Tax Credit
PV	Photovoltaics
PVC	Project Viability Calculator
RAM	Renewable Auction Mechanism
REC	Renewable Energy Credits
RET	Renewable Energy Target
REV	Reforming the Energy Vision
RFO	Request for Offers
RFP	Request for Proposals
RFQ	Request for Qualifications
RO	Renewables Obligation
RPS	Renewable Portfolio Standard
SCE	Southern California Edison
SDG&E	San Diego Gas and Electric
SENE	Scale Efficient Network Extensions

SEP	Supplemental Energy Payments
SMUD	Sacramento Municipal Utility District
SRES	Small-scale Renewable Energy Scheme
SWIS	South West Interconnected System
TURN	The Utility Reform Network
UCS	Union of Concerned Scientists
UK	United Kingdom
WECC	Western Electricity Coordinating Council

2 Executive Summary

2.1 Objectives

The Government of Alberta announced its objective to increase the amount of renewable generation in Alberta, with a goal of having renewable resources account for up to 30% of electricity generation by 2030.[1] This objective is part of several other policy components of the Government's Climate Leadership Plan. The Alberta Electric System Operator ("AESO") has recently been tapped to play a key role in the implementation of Alberta's policy to encourage the development of more renewables. As such, the AESO is seeking a better understanding of:

- approaches used in other jurisdictions to increase renewable generation;
- an understanding of how these policy mechanisms were designed (including how prices were determined, how procurement processes were managed, and how transmission was addressed);
- how those jurisdictions compare to Alberta; and
- implications for Alberta.

This report provides a description of how five jurisdictions have increased renewables using centralized procurement processes. Those jurisdictions, selected by the AESO, include: Australia, California, New York, Ontario, and the United Kingdom ("UK").

2.2 Summary of case studies

As the table below summarizes, the five case studies analyzed differed significantly. While New York's process has been ongoing for 10 years, Australia's first process is underway and Ontario just announced its winning bidders in its Large Renewable Procurement. While New York and the UK are procuring environmental attributes, other processes focus on the bundled product (commodity plus environmental attributes). All processes except Australia allowed different renewable technologies to compete against one another. The time to manage the competitive processes varied significantly, driven somewhat by the experience of the jurisdiction in managing procurement processes - from a low in New York of three to four months for its tenth solicitation to a lengthy two year timeframe in Ontario for its first competitive process for renewables.

[1] See http://www.alberta.ca/climate-coal-electricity.cfm

Figure 1. Comparison of competitive procurement processes

	Australia	California	New York	Ontario	United Kingdom
Program manager	Agency	Utilities with regulatory guidance	Agency	System operator	System operator
Product	Bundled	Bundled	Env. Attributes	Bundled	Env. attributes
Technology	Large Solar PV only	Multiple	Multiple	Multiple	Multiple
Term	Undecided[2]	10-20 years	Initially 10 years, now up to 20 years	20 years	15 years
Timeframe for process	About 1 year	12-18 months	3-4 months	1 year	9-10 months
MW installed to date	None – first process underway[3]	11,240 MW	2,512 MW	455 MW contracted	2,000 MW contracted

2.2.1 Australia

Australia's Federal Government has a renewable target of 33,000 GWh by 2020 and is about halfway to meeting this target. The Australian Renewable Energy Agency ("ARENA") plays a pivotal role in the renewables centralized procurement programs, setting the procurement goal, designing the procedure, conducting the competitive evaluation and overseeing the process. So far there has been only one competitive procurement targeting large-scale solar Photovoltaics ("PV") projects and the procurement is still ongoing. The evaluation of applications is based on announced eligibility and merit criteria, including a cap on the cost/MWh (AUS$135/MWh) and

[2] Note that this is financial support structured through a grant.

[3] Note that Australia had an earlier version of this procurement process, the Flagship Solar Procurement. It was largely unsuccessful, due to insufficiently strict evaluation criteria and development milestones, and this process was developed learning from mistakes made in that process. One 150 MW facility was eventually – very belatedly – developed as a result of the Flagship procurement.

a floor on the project's installed capacity (5 MW). Bidders compete with each other on both competitiveness and deliverability of the projects. A total of AUS$100 million will be allocated to winning bidders through a one-time grant to try to achieve ARENA's goal of bringing down costs to less than AUS$100/MWh by 2020. ARENA expects to announce winning projects by the end of 2016.

2.2.2 California

In 2015, California increased its final RPS target to 50% by 2030 along with several interim goals, including a 33% renewable target by 2020. The RPS goals and regional planning requirements are set based on reliability studies performed by California Independent System Operator ("CAISO"). The California Public Utilities Commission ("CPUC") plays an important role in overseeing the procurement processes for each of the utilities in California. There are several RPS procurement programs within the state; each one is operated by the individual utilities, in order to provide maximum flexibility in attaining the overall goal. The two main competitive procurement processes are the utility scale Request for Offers ("RFOs") and a Renewable Auction Mechanism ("RAM"). These programs are responsible for a majority of the state's renewable generation procurement, which have in aggregate have resulted in 11,240 MW of new operational renewable capacity. The utility scale RFO is held annually by each of the investor-owned utilities ("IOU"), and overseen by the CPUC and an independent evaluator; offers are evaluated based on pre-determined criteria in a project viability calculator. The RAM auctions are also conducted by each of the three individual IOUs for smaller renewable projects as part of an expedited process with standard non-negotiable contracts.

2.2.3 New York

New York has recently increased its renewable target to 50% by 2030 and is in the process of revamping its approach to encouraging and supporting the development of renewable energy. The regulator in New York, the New York Public Service Commission ("NYPSC"), plays an important role in setting key elements to the procurement targets and approach, and in overseeing the overall procurement process. The New York State Energy Research and Development Authority ("NYSERDA") has served as the procurement manager for its large scale projects, called Main Tier, for the last 10 years. Those procurement processes have resulted in 2,512 MW of new renewable capacity being developed in New York. New York's approach has differed from many other jurisdictions in that it has only contracted for the environmental attributes of the renewable electricity, requiring winning bidders to sell its commodity output in the wholesale market. All eligible renewable technologies compete against one another in each RFP and winning bidders are based on lowest possible price (70% of total assessment score) and the economic benefits (30% of assessment score) that the project can offer New York. NYSERDA uses a non-public maximum price that serves to weed out overly expensive projects. NYSERDA also reserves the right to negotiate bilaterally with bidders during the RFP process.

2.2.4 Ontario

Ontario has recently increased its renewable target to 20,000 MW by 2025. The Large Renewable Procurement ("LRP") is an endeavor by the Ministry of Energy and the Independent Electricity System Operator ("IESO") to change their approach to procuring renewables and to enhance community engagement in the RFP design process.[4] The Ministry of Energy and the IESO play an important role in setting key elements to the procurement targets and approach, and in overseeing the overall procurement process. Ontario launched its new competitive renewable procurement in 2014 with a consultation on the procurement design beginning in 2013. All eligible renewable technologies compete against one another and winning bidders are based on the lowest possible price subject to transmission/distribution availability depending on the project's connection point. The IESO uses a public maximum weighted price as a method to deny overly expensive projects. The IESO recently announced 16 winning bidders for a total of 455 MW from the first procurement.

2.2.5 United Kingdom

The United Kingdom ("UK") has a renewable target of 15% renewable energy consumption by 2020. It previously used a green tradable certificate based compensation to encourage renewable development and has recently moved to a centralized procurement approach called a Contract for Difference ("CfD") procurement. The CfD was developed by the Department of Energy & Climate Change ("DECC") and transmission system operator National Grid serves as the procurement manager. The first allocation round ended in March 2015. The successful applicants include mostly onshore wind and solar PV projects, totaling around 2 GW of installed capacity. The CfD scheme differs from its counterparts in that it provides contingent compensation from government to targeted renewables generators depending on the future difference between market prices of electricity and the pre-agreed "strike" prices. Applicants compete against others on the "strike" prices submitted as sealed bids. The scheme is designed to provide increased price stability to renewable generators, and to attract greater investment and lower the nation's emissions, while reducing cost impacts on ratepayers.

2.3 Key findings

2.3.1 Procurement targets

- **Overall goal and interim timelines**: Based on best practices observed in other jurisdictions, it is important to develop a specific goal (as a percentage of retail sales or consumption or a specific MW target) and then to set several interim milestones to achieve that goal.

- **Procurement target**: Most jurisdictions set a MW or GWh target for each procurement process. That target is usually set in function of the overall goal and size of the electricity market. It is important that the goal be large enough to motivate bidder participation. Thus it would be reasonable to set the goal at a level where there might possibly be several winning bidders. Based on the average size of renewable energy projects currently in the AESO's queue, which is about 150 MW, it would be reasonable to assume that a target of 450 to 500 MW might be a good starting point for Alberta's first procurement process.

[4] It previously used a Feed in Tariff for utility scale projects but that approach was roundly criticized for being too expensive.

- **Product definition:** Based on the experience in the five case studies and on LEI's experience working on renewable energy projects across North America, developers prefer a bundled commodity and environmental attribute product, although using a Contract for Differences structure can achieve much of the same revenue security that they are seeking. Developers need revenue security to ensure the lowest cost financing available. Financing solely on the environmental attributes does not usually provide enough price security and results in higher financing costs, which can translate into a higher premium for environmental attributes.

- **Eligible technologies and projects:** As the case studies show, it is generally the industry standard to allow different technologies to compete against one another. Including a broad variety of renewables allows for robust price competition and will enable a more diverse portfolio of technologies than would otherwise emerge. However, this approach means that the lowest cost renewables are likely to result as winning projects and does not give policymakers much control over resource diversity. Indeed, most jurisdictions have seen very high percentages of wind winning such procurement processes. Most jurisdictions only allow new projects (which includes uprates to existing projects) to participate in these competitive solicitations, given that the goal is to develop incremental new renewable capacity.[5]

2.3.2 Procurement process

- **Stakeholder consultation process:** It is useful to take input from market participants on the detailed implementation plan, RFP design, and contract templates for the procurement process. Market participants can offer creative ideas and identify potential implementation challenges which will improve the overall process.

- **Procurement manager:** It is crucial that the designated procurement manager be impartial – have no vested interest in who wins the procurement process or in how much capacity is procured – and qualified, with experience managing procurement processes with the requisite economic, legal, and engineering expertise to select the best qualified lowest priced bids. Both Ontario and the UK have selected their system operators to serve in this capacity, as was recently announced for Alberta.

- **Timeframe for procurement process:** It is likely to take at least 12 months for the first large scale procurement process to be conducted. That timeframe is likely to shorten with experience, as seen with NYSERDA who now conducts solicitations within a three to four month timeframe.

- **Qualifications assessment:** While the price of bids is a major focus in the bid evaluation process, it is also important to assess the experience of the bidder team to ensure that they have a reasonable expectation of being able to develop the project on time and to operate

[5] However, as existing plants come off contract, there will be increasing pressure to allow them to participate (or receive some other kind of compensation, rather than shut down.

it successfully. At the same time, expectations of the bid team need to be scaled to the size of the project being bid into the process.

- **Bid deposits and contract securities:** Bid deposits serve to demonstrate the seriousness of the team proposing a project and help to prevent frivolous bids. Contract securities, which are provided after the project has won a procurement process but before the project achieves commercial operation, serve as a useful motivator to ensure that the project is developed on time and at the capacity committed to in the proposal. It is LEI's view that deposits and securities should be scaled to the size of the project being bid into the process, so that smaller developers are not discouraged from participating in the procurement process.

- **Bilateral negotiation:** The objective of a competitive procurement process is to ensure that all market participants have a fair chance in the process with the evaluation criteria publicly disclosed. It is LEI's view and general best practice that well-designed public procurement processes should not require much, if any, bilateral negotiation, other than on site-specific issues.

- **Third party oversight:** Even with an objective entity like a government agency or system operator running a procurement process, having a secondary level of evaluation or oversight over the procurement process and the ultimate bid selection process will provide assurance that the process is a competitive and fair one. Third party oversight can also be helpful at providing constructive suggestions for ways the process can be improved in any subsequent processes.

- **Contract terms:** NYSERDA started with 10 year terms and transitioned to 20 year terms in recent years in response to perceived developer needs. Most other jurisdictions use 15 to 20 year contracts.

2.3.3 Quantitative bid evaluation

- **Price-setting mechanism:** There are two approaches to price-setting in competitive procurements – granting bidders the price that they bid or granting all bidders the last price that "cleared" the auction (called a "market clearing price"), similar to how wholesale energy markets function. There is significant economic research advocating either approach. Some economists voice concern that a market clearing price is "overpaying" bidders that bid in at a lower level. At the same time, other economists argue that the price as bid model encourages gaming and strategic bidding. There is no conclusive evidence on this point. In the case studies we analyzed, only the UK uses a market clearing price setting mechanism. In addition, from an administrative point of view using a price as bid mechanism is simpler to administer.

- **Transmission costs:** If transmission needs to be developed, LEI believes that it is preferable to include it in the bid evaluation process so that the overall cost of developing the interconnected renewable energy project can be fairly compared. Otherwise, it makes sense to require projects to demonstrate their ability to interconnect, as is the case in many of the procurement processes that we looked at.

- **"Not to exceed" price cap:** It is generally best practice to have a maximum price cap on what the procurement manager is willing to pay in a given procurement process. This cap should be based on up to date data on local development costs and should include all costs incurred by developers. While some jurisdictions make this cap public, in a jurisdiction that is just starting such procurement processes it may make sense to either take stakeholder feedback on preliminary cap levels or to keep the cap confidential for the first process, and to use the bids from the first process to develop a public and binding cap for subsequent processes.

- **Other policy goals:** Those goals might include technology preferences, locational preferences, economic development targets, and community engagement priorities. While these other policy goals can be included in the RFP, it is LEI's view that incorporating them adds complexity and administrative ambiguity to the bid evaluation process. If included, it is vital that these criteria be explicitly detailed and that the way in which those criteria will be factored into the quantitative bid evaluation is clearly spelled out in the RFP.

3 Key findings and implications for Alberta

This section provides a comparison of the five case studies and identifies similarities, differences, and best practices. We also highlight key findings and implications specific to Alberta. The first subsection focuses on comparing market characteristics and renewable energy policy to give the reader a better understanding of how these jurisdictions differ from one another and from Alberta. The subsequent subsections, one of which focuses on the centralized procurement process design while the other focuses on how these processes ensured competitive outcomes, compare the jurisdictions against one another and identify best practices and implications for Alberta.

3.1 Comparison of market characteristics and renewable energy policies

The Alberta electricity market has several unique characteristics. By installed capacity, currently at almost 17,000 MW, it is one of the smallest organized wholesale markets in North America. Its energy-only market design means that investors must rely on peak prices alone to provide a sufficient incentive to invest in new generation projects. Alberta does not have locational marginal pricing, limiting pricing signals to developers of new generation. Alberta has limited interconnections with neighboring regions. Finally, Alberta has a large proportion of industrial load in its customer mix, some of which is very sensitive to increases in electricity prices and which contributes to a high system load factor.

Most of the markets assessed in the case studies have quite different market characteristics, as shown in the table below. All are significantly larger than Alberta in terms of installed capacity. Only Australia has a considerable amount of coal-fired capacity and only Australia and the UK have sizable industrial consumption, though significantly less than in Alberta. Australia is the only jurisdiction that also has a pure energy-only market design. Given these differences, it is important to consider how the procurement processes in these jurisdictions might translate to the Alberta market. We highlight those points in this section and in the "implications for Alberta" subsection at the end of each case study.

All of the jurisdictions analyzed had ambitious targets for new renewable energy deployment, ranging from the UK's EU-driven target to achieve 15% of energy consumption from renewables to New York and California which both recently announced updated goals of achieving 50% of retail electric sales from renewables by 2030. California has explicitly set out a schedule of interim goals, while New York is planning a triennial review process that will update interim milestones. The jurisdictions that did not have interim milestones generally had shorter term targets. All the jurisdictions reviewed had a combination of policies in place to encourage the development of renewables. Most jurisdictions used feed in tariffs or specific financial incentives for small or customer-sited renewables. Both the UK and Ontario have introduced centralized procurement approaches to replace more expensive utility-scale renewable incentives – feed in tariffs in Ontario (though centralized procurement predated its FIT approach) and a quota obligation system in the UK.

Figure 2. Comparison of market characteristics

	Australia	California	New York	Ontario	United Kingdom
Installed capacity (MW)	62,985 MW	78,865 MW	38,665 MW	35,221 MW	84,987 MW
% coal generation	61%	0%	3%	0%	30%
% renewable generation[6]	15%	23%	26%	30%	20%
% industrial consumption	34%	24%	9%	24%	31%
Market design	Competitive energy-only market	Largely contracted with wholesale market for specific products	Competitive energy market, including capacity market	Centrally managed for new generation; real-time spot market	Competitive energy market, including capacity market
Cap on bid prices[7]	AUS$12,500/ MWh	US$1,000/ MWh	US$1,000/ MWh	Cdn$ 1,000/ MWh	None

[6] Note that this row reflects total generation from all renewable technologies. This might not all be counted toward a jurisdiction's renewable target as certain jurisdictions exclude older renewables or some renewable technologies from that target.

[7] All currencies listed in national denomination. For comparison purposes, the exchange rate in mid-March was: AUS$1=Cdn$1; US$1=Cdn$1.34; 1 British Pound =Cdn$1.91.

Figure 3. Comparison of RPS design elements

	Australia	California	New York	Ontario	United Kingdom
Total target/ timeframe	33,000 GWh by 2020	50% by 2030	50% by 2030	20,000 MW by 2020	15% energy by 2020
Interim goals	None	25% by 2016; 33% by 2020; 40% by 2024; 45% by 2027	30% by 2020; triennial goals likely	None	30% electricity; 12% heat; 10% transport
Support mechanisms used	Competitive procurement, feed in tariffs, tax-incentives, quota obligations	Competitive procurement, auction mechanism, feed in tariffs and a specialized program targeted at solar rooftop development.	Currently, centralized procurement and financial incentives for smaller scale renewables[8]	Centralized procurement; feed in tariffs	CfD, feed in tariffs, Carbon Price

3.2 Centralized procurement process

3.2.1 Comparison across case studies

In many jurisdictions, notably Australia and New York, the competitive procurement process was run by a government agency. In Ontario and New York, it is run by the system operator and in California, it is run by the utilities guided by the regulator, as shown in the table below.

[8] As discussed in Section 6, New York is revamping its approach to renewable support mechanisms. It is contemplating transitioning to a more traditional quota obligation program, supplemented by targeted centralized procurement and additional financial incentives.

Figure 4. Comparison of centralized procurement process

	Australia	California	New York	Ontario	United Kingdom
Program manager	ARENA	Utilities with regulator guidance	NYSERDA	IESO	National Grid
Product	Bundled	Bundled	Env. attributes	Bundled	Env. attributes
Technology	Large Solar PV only	Multiple	Multiple	Multiple	Multiple
Eligible vintage	New	Open but limits on existing facilities	After 2003	New	New
Term	Undecided	10-20 years	Initially 10 years, now up to 20 years	20 years	15 years
Timeframe for process	About 1 year	Utility scale RFO: 500 days RAM: 6 months	3-4 months	1 year	9-10 months
Transmission issues	Transmission cost included in bid	Transmission cost included in bid	Projects must demonstrate ability to interconnect	Factored as part of evaluation process	Must be able to interconnect
MW installed to date	None – first process underway[9]	11,240 MW	2,512 MW	455 MW contracted	2,100 MW contracted

[9] Note that Australia had an earlier version of this procurement process, the Flagship Solar Procurement. It was largely unsuccessful and this process was developed learning from mistakes made in that process. One 150 MW facility was eventually – very belatedly – developed as a result of that procurement.

Most jurisdictions procure a bundled product – the electric commodity and its environmental attributes. New York has historically procured only the environmental attributes but is considering transitioning to a bundled product. The terms for contracts are usually 15 to 20 years. These procurement processes take time to run, many last at least a year until contracts are signed, though New York completed these processes in three to 4 months after 10 years of experience, which suggests that there is a learning curve. Transmission issues are addressed differently. Some jurisdictions, such as New York and the UK, require that the project demonstrate its ability to interconnect as part of the eligibility criteria. Other jurisdictions, such as Australia and California, require developers to include the costs for transmission upgrades with their bids. Ontario takes a hybrid approach, requiring projects to demonstrate their ability to interconnect and then ranking projects by interconnection point so that the lowest cost projects are selected first.

3.2.2 Best practices and implications for Alberta

- **Overall goal and interim timelines:** The Alberta government has announced that it is developing a new strategy on climate change based on recommendations put forward by the Climate Change Advisory Panel. That plan will include phasing out coal-generated electricity and developing more renewable energy, as well as implementing a new carbon price on greenhouse gas pollution (among other actions).[10] It is LEI's view that Alberta's goal needs to be specified into a percentage of retail sales or consumption target, or a specific MW installed target. Given the 2030 date, and best practice in other jurisdictions, using several interim milestones would help identify any challenges to meeting the 2030 goal sufficiently early to put in place midpoint corrections.

- **Procurement manager:** It is most common for a government entity, single buyer, or system operator to serve as the procurement manager. Those entities are impartial – i.e., they have no vested interest in who wins the procurement process or in how much capacity is procured. If market participants, such as a utility, serve as the procurement manager, it is important for a regulatory body or other independent entity to design the procurement process and to closely oversee the market participant serving as procurement manager, as seen, for example, in California. At the same time, it is important that the procurement manager have deep experience managing procurement processes with the requisite economic, legal, and engineering expertise to select the best qualified, lowest priced bids. The system operator serves as the procurement manager in Ontario and the UK, as will be the case in Alberta.

- **Public stakeholder consultation process:** While the procurement manager will take the lead on scoping out the procurement design and developing draft contracts, it is crucial that market participants provide input on both. There are innovative ideas that market participants may be able to offer that will improve the process. In addition, market participants will also be able to identify any specifics in the draft contract that might provide problems executing contracts after the process is complete. It is best to identify any such challenges before the RFP is issued to ensure robust bidder participation. This

[10] Alberta Government. *Climate Leadership Plan*. Accessed March 29th, 2016. <http://www.alberta.ca/climate-leadership-plan.cfm>

process of taking public feedback does take time, which needs to be factored into the overall procurement schedule. The case studies show that it can take anywhere from several months to more than a year to conduct that stakeholder consultation process. It is LEI's view that such processes usually take six to 12 months.

- **Product definition:** Based on our review of the case studies and our experience working on renewable energy projects in North America generally, developers tend to prefer contracts for a bundled commodity and environmental attribute product. However, using a Contract for Differences structure can also achieve many developer needs, usually at a lower overall cost. Developers need price security to secure the lowest cost financing available. Financing only based on revenues from contracting the environmental attributes does not provide enough price security to developers and results in higher financing costs, which translates into a higher premium for environmental attributes. Because Contract for Differences provide a "floor" revenue level, developers are more easily able to finance their plants.

- **Eligible technologies:** Allowing different renewable technologies to compete is the industry standard. The only exception in the case studies we analyzed was in Australia, which is focused on decreasing the cost of large scale solar because Australia has a high potential for solar. Including a broad variety of renewables allows for robust price competition and may enable a more diverse portfolio of technologies. However, it is important to acknowledge that this structure will favor the lowest cost renewables and will not enable policy makers to ensure a balanced portfolio of different renewable technologies. Indeed, as seen in the UK, Ontario, and in New York, which all permit multiple technologies to compete, wind projects still end up with the majority of winning contracts.

  In addition, unless factored into the bid evaluation process, all-technology procurement processes can be challenging for technologies that take longer to come on-line, such as geothermal and hydro. Using data from resource mapping to assess which technologies are viable is a useful first step to understand what technologies might be cost competitive in Alberta.

- **Transmission costs:** If transmission needs to be developed in order to facilitate the interconnection of new renewables, those costs are usually included in the bid evaluation process. This means that the aggregate cost of developed renewables can be compared against one another so that projects that do not require transmission investment, or projects that have lower transmission investments, are shown to be the most cost-effective in the bid evaluation process. If transmission buildout is not required, demonstrating the ability to interconnect may be sufficient. In the Alberta market, new transmission may eventually need to be developed to facilitate the development of this magnitude of renewable generation. Once that point is reached, it would make sense to have transmission factored in as an explicit economic component of the analysis. However, Alberta's transmission regulations may not allow this approach, and will require review to understand what might be feasible with existing regulations. An overview to how each of the case studies addressed transmission issues is shown in the table below.

Figure 5. Comparison of transmission issues by jurisdiction

	Australia	California	New York	Ontario	United Kingdom
Must projects be able to interconnect?	Yes	No	Yes	Yes	Yes
How demonstrated?	Connection agreement	N/A	Grid system queue #	Connection availability test	Connection agreement or path to interconnect
If not, is assessment of transmission required?	N/A	Yes, CAISO inter-connection study	N/A	N/A	N/A
Do costs for transmission need to be in price bid?	Yes	Yes	N/A	N/A	N/A
Is transmission evaluated in any other way?	No	Included in qualif-ications assessment	No	Lowest price projects with available inter-connection capacity taken first	No

- **Contract terms:** In the case studies we analyzed, most contracts range from 15 to 20 years. NYSERDA started with 10 year terms and transitioned to 20 year terms in recent years in response to developer needs.

- **Timeframe for procurement process:** Based on experience in other jurisdictions, it will take at least 12 months for the first large scale procurement process to be conducted. It is likely that subsequent procurements could be shorter, once contract templates are finalized and the procurement manager becomes more adept at running the process, as seen with NYSERDA who now conducts solicitations within a three to four month timeframe.

3.3 Mechanism to ensure competitive outcomes

3.3.1 Comparison across case studies

Most jurisdictions rank bids based on price – sometimes in groups based on technology or size – and select the least cost qualifying bids, paying projects the price they bid. Notable exceptions include the UK CfD process, which uses an auction clearing price for all bidders, which means that some bidders will receive more than they bid. Most jurisdictions establish a not to exceed price per MWh for the process; this can sometimes vary by technology. Note that setting this not to exceed price is a process that requires careful consultation with developers as procurement agencies often lack a thorough and up to date understanding of the full costs of development. In many jurisdictions that price is disclosed publicly in the RFP documents although it is confidential in New York.

Only New York and Ontario use other criteria as an explicit part of their quantitative ranking of projects – factoring in local economic benefits in New York and level of engagement with local and Aboriginal communities in Ontario. Both Australia and California have non-financial criteria that they consider as part of the overall bid evaluation process but these factors do not affect the ranking of financial bids. Ontario, Australia, and the UK explicitly forbid bilateral negotiation in all circumstances while California allows it with no restrictions, and New York allows it after financial bids have been submitted.

Most jurisdictions require both bid deposits and contract securities as a way to discourage frivolous bids and ensure that projects are developed on a timely basis, though quantities required vary substantially. Third party oversight is used in all jurisdictions except for Australia.

The table on the next page provides a comparison of all of these elements across the five case studies.

Figure 6. Comparison of mechanisms to ensure competitive outcomes

	Australia	California	New York	Ontario	United Kingdom
Qualifications assessment	Yes - EOI	Yes	Yes – Qualifications process	Yes - RFQ	Yes
Price setting mechanism	Price as bid	Price as bid	Price as bid	Price as bid	Auction clearing price
Not to exceed price	Yes, public	No	Yes, confidential	Yes, public	Yes, public
Other Criteria	Minor	Minor	Local economic benefits	Engagement with local/ aboriginal communities	None
Ability to negotiate bilaterally	No	Yes, for utility scale RFOs No, for RAM	Yes	No	No
Bid deposit	No	Yes	Yes	Yes	No
Contract security	Yes	Yes	Yes	Yes	No but other requirements
Third party oversight	No	Yes	Yes	Yes	Yes

3.3.2 Best practices and implications for Alberta

- **"Not-to-exceed" price cap:** Most competitive procurement processes use a maximum "not to exceed price" on what the procurement manager is willing to pay in a given procurement process. This is intended to ensure that the procurement manager does not accept bids that are "out of the market," i.e., at a price that is considered significantly above market prices. Depending on the structure of the procurement process – whether it is requiring different technologies to compete against one another on the nature of price or whether it is trying to achieve a diverse portfolio of different renewable technologies that might be a portfolio cap or a technology cap. It is crucial that the procurement manager solicit input from local developers to establish that not-to-exceed price to ensure that it reflects all the costs required to develop a project and that those costs reflect local conditions. A comparison of how each of the five jurisdictions used their price cap is shown in the table below.

Figure 7. Comparison on how each jurisdiction used price cap

	Australia	California	New York	Ontario	United Kingdom
Name	Levelized cost of energy	Market Price Referent	Maximum Bid Price Evaluation Metric	Maximum Weighted Prices	Administrative Strike Price
Binding	Yes	No	Yes	Yes	Yes
Public	Yes	Not until after the solicitation	No	Yes	Yes
Vary by technology	Yes (solar only)	No	No	Yes	Yes
How set	Not specified	Based on levelized cost of CCGT using full costs and updated fuel estimates	Not specified	Using IESO's internal data, industry feedback, N. American and international price trends	Based on National Grid's modeling and feedback from stakeholders

- **Price-setting mechanism:** Two main approaches to price-setting exist in competitive procurement processes. Either bidders are granted contracts at the price that they bid ("price as bid") or all bidders receive the last price that "cleared" the auction (usually referred to as "market clearing price" or "uniform auction price"), similar to how wholesale energy markets function. There is no conclusive evidence to date on which is more effective, although most of our case studies used a "price as bid" approach. The price as bid mechanism is also considered simpler to administer.

- **Other policy goals:** Those goals might include technology preferences, locational preferences, economic development targets, and community engagement priorities. It is LEI's view that including other policy goals in the bid evaluation process introduces subjectivity and increases the complexity of identifying winning proposals. Even when those criteria and how they will be factored into the quantitative bid evaluation are clearly spelled out in the RFP, they can make the economic evaluation more arbitrary and administrative.

- **Bilateral negotiation:** The goal of a competitive procurement process is to make sure that all market participants have a fair chance in the process. It is LEI's view, and general best practice, that well-designed public procurement processes should not require much, if any, bilateral negotiation. Bilateral negotiation should not be about price or any project specifics, but might be acceptable if limited to minor contractual terms or site specific details. As such, it would appear reasonable to request that bidders submit any suggested changes on the contract as part of the bid package or to limit bilateral negotiation to the phase after winning bidders have been notified. This will help to ensure confidence in the competitive and fair nature of the RFP process.

- **Qualification assessment:** While the price of bids is a major focus in the bid evaluation process, it is also important to assess the quality of the bidder team to ensure that they have a reasonable expectation of being able to develop the project on time and operated it as needed. Factors to be assessed include: experience developing similar size and technology projects; having sufficient financial backing; and having a team in place with the necessary expertise to develop and operate the project. This can be structured as the first phase – a qualifications assessment – or can be integrated into the overall bid evaluation.

- **Bid deposits and contract securities:** Bid deposits serve to demonstrate the seriousness of the team proposing a project and help to prevent frivolous bids. Contract securities, which are provided after the project has won a procurement process but before the project achieves commercial operation, serve as a useful motivator to ensure that the project is developed on time and at the capacity level promised. Similarly, contract securities can be used to ensure that projects are generating the MWh they committed to in the bid process. In addition, some jurisdictions are also using site restoration bonds to ensure that equipment is appropriately removed at the end of the asset's useful economic life, as seen with solar in Vermont. Note that these deposits and securities should be scaled depending on the size of the project so that there are not obstacles to smaller developers submitting proposals. It is useful in the RFP to spell out exactly what would cause those deposits and securities to be forfeited. Examples of deposit levels are shown below.

Figure 8. Comparison of bid deposits and contract securities

	Australia	California RFO	New York	Ontario	United Kingdom
Bid Deposit	Not required	US$3/kW	US$5,000-100,000 depending on project size	Cdn.$ 10,000 (Non-refundable)	Not required
Contract security	AUS$20,000 x project capacity (MW)	US$15/kW; after CPUC approval US$60-90/kW	US$6/MWh x annual bid quantity, increasing to US$9/MWh 1 year before COD	Cdn$50,000/ MW	Must demonstrate that at least 10% of project pre-commissioning costs have been spent within 1 year

- **Third party oversight:** Even with an entity like a government agency or system operator running a procurement process, having a secondary level of evaluation or oversight over the procurement process and the ultimate bid selection process will provide comfort that the process is a competitive and fair one. Third party oversight can also be helpful at providing constructive suggestions for way the process can be improved in the subsequent round.

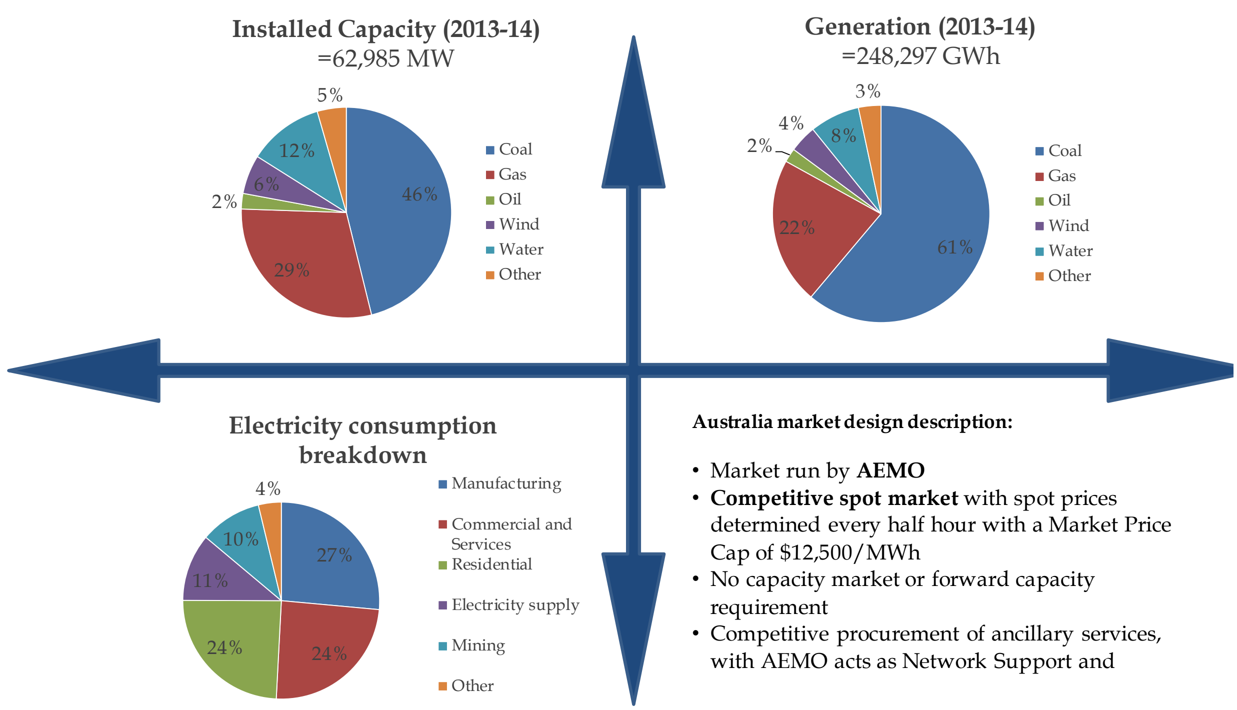
4 Australia – large scale photovoltaics

4.1 Context

4.1.1 Australia market characteristics

Australia has an installed capacity of 62,985 MW,[11] with coal composing about 50% of the total capacity. Australia's generation is mainly thermal, with coal and gas representing 61% and 22% of total generation, respectively. Australia's electricity consumption is balanced among customer categories with manufacturing, commercial, and residential each accounting for about a quarter of total electricity consumption.

Figure 9. Overview of Australia's electric power market characteristics



Source: Australian Government Department of Industry, Innovation and Science, AEMO.

[11] Australian Government Department of Industry, Innovation and Science. *"Energy in Australia 2015".* <http://industry.gov.au/Office-of-the-Chief-Economist/Publications/Documents/energy-in-aust/Energy-in-Australia-2015.pdf>

The National Electricity Market ("NEM") is the Australian wholesale electricity market and the associated synchronous electricity transmission grid. The NEM is the world's longest interconnected power system covering five interconnected regions – Queensland, New South Wales, Tasmania, Victoria and South Australia.[12] The Australian Energy Market Operator ("AEMO") is the administrator and operator of NEM. Wholesale trading in electricity is conducted as a spot market where supply and demand are instantaneously matched in real-time through a centrally-coordinated dispatch process. A Market Price Cap of AUS$12,500/MWh is the maximum price at which generators can bid into the market.[13] AEMO also operates separate markets for the delivery of frequency control ancillary services and procures network control ancillary services and system restart ancillary services under agreements with service providers.

Overview of Australia's large-scale solar PV competitive round:

- ARENA sets key elements to procurement targets and approach and also serves as the process manager
- Large-scale solar PV is currently the only targeted technology
- ARENA will provide a one-time grant to winning bidders which will cover partial cost of project
- Eligibility criteria include cap on cost (AUS$135/MWh) and floor on capacity (5 MW)
- Merit criteria evaluate both competitiveness and deliverability of projects
- Knowledge sharing component included in evaluation
- First procurement still underway

4.1.2 Australia renewable energy targets

Australia's Renewable Energy Target ("RET") is a Federal Government policy designed to ensure that at least 33,000 GWh of Australia's electricity comes from renewable sources by 2020, which implies doubling the current renewable generation and targeting 23.5% of total electricity generation from renewable sources by 2020. The RET was reviewed by the Government and reduced in June 2015 from the previously legislated 41,000 GWh to 33,000 GWh. The RET has been in place since 2001 and Australia is about halfway to meeting the revised 33,000 GWh target.

The RET is composed of two components: the Small-scale Renewable Energy Scheme ("SRES") which aims to lower the costs of renewable energy system installation for households, small businesses, and community groups, especially domestic solar PV systems; and the Large-scale Renewable Energy Target ("LRET"), which creates financial incentives for the establishment or expansion of renewable energy power stations, such as wind and solar farms or hydro-electric power stations.

Australia also offers feed in tariffs and tax incentives as a means of encouraging renewable energy development. Feed in tariffs are mostly state-based initiatives and are applicable to only small-

[12] Western Australia and Northern Territory have independent electricity suppliers.

[13] AEMO. *"An introduction to Australia's national electricity market."* July 2010. <http://www.abc.net.au/mediawatch/transcripts/1234_aemo2.pdf>

scale generation except in the Australian Capital Territory ("ACT") which has a Large Scale Feed in Tariff Scheme. Renewables are also eligible for the R&D Tax Incentive scheme.

4.2 Key process design attributes

Established on July 1, 2012, the Australian Renewable Energy Agency ("ARENA") is a commercially oriented government agency established to promote renewable energy in Australia. At its inception, ARENA assumed responsibility for managing projects that had already been procured by the former Australian Centre for Renewable Energy, the Department of Resources, Energy and Tourism, and the Australian Solar Institute.[14]

The Advancing Renewables Programme ("ARP") is a funding programme initiated by ARENA to support activities that reduce the cost or increase the value of renewable energy, advance renewable energy technologies towards commercial readiness, reduce or remove barriers to uptake, or increase relevant skills, capacity and knowledge.[15] ARENA runs one competitive procurement process under ARP, which targets large scale solar photovoltaics. This first procurement process is still underway and is expected to be completed by the end of 2016.

Note that Australia had an earlier centralized procurement approach from 2009 to 2014, the Solar Flagships Program, which procured large-scale, grid connected, solar power with the aim of procuring up to 1,000 MW of solar PV. The winner of the Solar Flagship Program included the 150 MW Moree Solar Farm PV project and the 250 MW Solar Dawn solar thermal project. However, there were difficulties in getting the utilities to sign the PPAs, due to uncertainty about the technology and project delivery, as well as low wholesale prices. This resulted in the cancellation of the Solar Dawn project and a massive delay to the Moree project. As a result, the Australian government revamped what it did in that procurement process, adding more specified and quantified criteria, a stricter evaluation process, tighter deadlines and different requirements on energy source and technologies. Given that the ARENA competitive procurement is intended to be an improvement on the Flaships program, we do not provide any other discussion of the Flagships' procurement approach.

4.2.1 Establishing resources needs

On July 14, 2015, ARENA released its updated General Funding Strategy and Investment Plan,[16] which stated that large scale solar PV would be one of the five top priorities for ARENA. On September 9, 2015, ARENA announced an AUS$100 million competitive process to allocate grants to large-scale solar PV. ARENA intends to bring down costs potentially to less than AUS$100/MWh by 2020 through the deployment of 200 MW of large-scale solar PV. Furthermore, ARENA intends to provide transparency and price discovery in relation to current

---

[14] ARENA. *History.* <http://arena.gov.au/about-arena/history/>

[15] ARENA. *Programmes.* <http://arena.gov.au/programmes/>

[16] ARENA. *General Funding Strategy.* <http://arena.gov.au/files/2015/07/General-Funding-Strategy.pdf>; ARENA. *Investment Plan.* <http://arena.gov.au/files/2015/07/Investment-Plan-2015.pdf>

and projected costs of large-scale solar PV through the sharing of forecast and actual costs of both successful and unsuccessful projects on an anonymous basis.

ARENA decided to prioritize large scale PV due to the following reasons:[17]

- ARENA has observed significant cost reductions in large-scale solar PV. The cost of producing solar is expected to become competitive without additional support in the medium term.

- Large-scale solar PV is in its infancy in Australia, putting Australia well behind comparable international markets despite having some of the best solar resources in the world.

- There is currently a wide cost gap between large-scale solar PV and other commercially competitive forms of power generation (including wind).

ARENA specified the following screening requirements for potential bidders:

- projects must generate all their electricity from solar PV;

- projects must be able to demonstrate that they have a Levelized Cost of Electricity ("LCOE")18 of AUS$135/MWh or less;

- projects must meet or exceed the minimum project size of 5 MW (AC);

- total grant funding requested for a project must not exceed AUS$30 million;

- projects must be connected to the NEM or the South West Interconnected System ("SWIS"); and

- projects must not involve behind the meter elements.

4.2.2 Managing procurement process

In addition to setting the targets for the large scale solar procurement, ARENA also designed and is managing the procurement process. That process involves two stages: an initial Expression of Interest ("EOI") and a Full Application. All applicants must meet the pre-specified eligibility and merit criteria.[19]

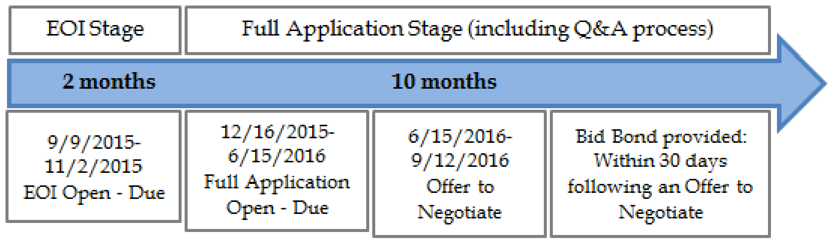
---

[17] ARENA. <http://arena.gov.au/programmes/advancing-renewables-programme/large-scale-solar-pv/>

[18] Levelised Cost of Electricity calculated over 25 years of P50 generation (sent out) at a pre-tax, mid-period, discount rate of 10%.

[19] Details of both sets of criteria can be accessed through: http://arena.gov.au/files/2016/02/Advancing_Renewables_Programme-Guidelines.pdf

Figure 10. Overview of Large-scale Solar PV competitive round



Source: ARENA

ARENA's ARP Programme Guidelines define the rules for ARENA's Competitive Processes unless there are explicitly announced changes. When ARENA establishes a competitive procurement, it will announce the start of a Competitive Process on the Programme webpage.[20] The Competitive Process will rank eligible proposals based on an assessment against the merit criteria, listed in the table below, subject to ARENA's portfolio approach. Projects with the highest rankings will be offered funding subject to the level of funding indicated for the competitive round.

Figure 11.Eligibility and Merit Criteria of ARP

Eligibility Criteria
Eligible applicant
Eligible activity
Take place in Australia
Knowledge sharing
Intellectual property
Merit Criteria
Contributes to the Programme Outcomes
Applicant capability and capacity
Activity design, methodology, risk and compliance
Financial viability and co-funding commitment
Knowledge sharing

Aside from the criteria listed above, ARENA also gives consideration to how a project will contribute to the Programme Outcomes either uniquely or as part of a suite of complementary ARENA projects. A higher ranked project might not be selected if the aims or outcomes of that project are the same as, or similar to, those of a project that has previously been funded or that ARENA is intending to fund. This is reflected in ARENA's Portfolio Approach.

[20] The Funding Announcement will include information on: a) the level of funding available under the Competitive Process for eligible Activities; b) the application and assessment process, including deadlines for application submission and the stages of application (ie EOI, Full Application); and c) clarifications of eligibility and merit criteria as they apply to the Activities, including clarification of any criterion that will not apply to the Competitive Process.

ARENA specified certain limitations for the large-scale Solar PV Competitive Round:

- no less than 50% of the total funding allocation can be offered to projects connected to the NEM; and,
- no more than 50% of the total funding allocation can be offered to majority owned utility projects.

In addition, ARENA may also consider: 1) the capability of each applicant (including key consortium members) to deliver across multiple projects (where applicable); 2) any relevant limits on the availability of off-take from a single off-taker; and 3) any relevant limits on funding from a single financier. For the large-scale solar PV competitive round, evaluation at both EOI and Full Application stages are based on the eligibility and merit criteria listed above. A detailed description of the specific criteria is discussed in the following paragraphs:

Expressions of Interest ("EOI")

The EOI is essentially a qualification round. In the submitted EOI, applicants need to include:

- **Contributions to the Programme Outcomes:** Brief description of the proposed project and how it will contribute to the ARENA programme outcomes, the investment focus areas in ARENA's investment plan and any relevant funding announcements;
- **Financial viability and cofounding commitment:** Details of the contractors and indicative contract terms of third party contractors; a budget for the project;
- **Applicant capability and capacity:** Brief description of the quality, capability and capacity and the relevant expertise of the key personnel and partners;
- **Project design, methodology, risk and compliance:** The resources to be used to deliver the project, the indicative project phases, milestones and duration; and,
- **Knowledge sharing:** The value of knowledge and information created by the project and the execution plan of creating and sharing that knowledge and information.

All shortlisted applicants after the EOI stage should meet the requirements in eligibility criteria.

Full Application[21]

During the full application stage, there are usually more requirements than those at the EOI stage. For example, for the large-scale solar PV competitive round, ARENA listed the following additional clarifications and requirements:

[21] Detailed criteria can be accessed through: <http://arena.gov.au/files/2016/01/LSSPV-Funding-Announcement-updated.pdf>

- **Contributes to the Programme Outcomes:** ARENA will consider: (i) the cost competitiveness of the project measured and assessed according to the amount of ARENA grant funding requested per MWh of estimated net generation; (ii) the LCOE of the project; (iii) how the project will reduce costs or deliver additional value; and (iv) the extent to which the project attributes can be replicated and provide a clear path for further cost reductions;

- **Applicant capability and capacity:** Similar with that in the EOI stage only in more details;

- **Project design, methodology, risk and compliance**: ARENA will consider: (i) the quality and completeness of the project plan; (ii) the quality of the risk management plan; and (iii) the quality of the workplace health and safety plan and the extent to which the applicant accepts the terms of the proposed ARENA funding agreement;

- **Financial viability and cofounding commitment**: ARENA will consider: (i) the deliverability of the financing plan; (ii) the level of conditionality of the funding commitments; and (iii) the level of financial transparency of the project and risk of cost overruns;

- **Knowledge sharing**: ARENA will consider: (i) how well the knowledge generated will contribute to the objectives of the competitive round; (ii) the extent to which the applicant is willing to comply with ARENA's knowledge sharing plan; (iii) the extent to which additional valuable knowledge may be generated and shared from the project; and (iv) where relevant, the applicant and/or the applicant consortium's track record in providing knowledge under existing ARENA supported projects;

- **Exchange and interest rate sensitivity clarification:** Any sensitivity to changes in foreign exchange and interest rate movements need to be reported. Applicants need to propose approach to foreign exchange and interest rate risk management.; and,

- **Project offtake arrangements:** Applicants should submit documentation regarding a project's offtake arrangements, if applicable.

Full Applications will be ranked against the ARP merit criteria, with each criterion being given equal weight in the assessment process. The highest ranked High Merit Projects will be recommended for funding subject to the total funding allocation available and the portfolio approach.

Q&A process

ARENA allows bidders to submit questions during the full application process. Questions received and ARENA's responses will be provided to all Applicants except where:

- the Respondent nominates in its Question that its enquiry relates to proprietary information relevant to its Application;[22] and
- ARENA is of the opinion that the question and ARENA's response are not material to the integrity or the competitiveness of the Competitive Round.

Project Bid Bonds

After ARENA identifies the highest ranking project(s), ARENA will issue an offer to negotiate an ARENA funding agreement to applicants within 90 days of the full application due date. Within 30 days of receiving the Offer to Negotiate, the Applicant must provide ARENA with a Bid Bond, the face value of which will be an estimate of the costs to ARENA in seeking a replacement project should the Applicant's project not proceed to Project Financial Close.[23] That amount is set at AUS$20,000 x Project Capacity (MW (AC)) (subject to a minimum of AUS$250,000 and a maximum of AUS$500,000). The bid bonds will be returned to the applicant if the applicant meets the project financial close on time.

Other security requirements

Prior to Project Financial Close, the involved parties must enter into the Independent Certifier ("IC") Agreement. Generally speaking ARENA will require the IC to confirm payment claims and confirm any Recipient/Superintendent/IC certifications under the Project Documents which are required for withdrawals of Funds. The costs of this review by the IC will be borne by the Recipient.

During the construction of winning projects, ARENA has the right to undertake, or engage an expert to undertake, at its own cost, a review or development of the Project not more than once every three months (except where an Event of Default has occurred and is continuing). An independent audit appointed by the recipient has the responsibility to undertake audits on relevant projects under the Independent Audit Agreement.

4.2.3 Ensuring competitive outcomes

Several features are embedded in the competitive process to foster a competitive outcome.

Publication of information

ARENA will publish anonymous data from the proposals received at the conclusion of the EOI and Full Application stages in order to provide a high level of transparency to stakeholders on

[22] If ARENA is of the view that the question is not proprietary, it will advise the relevant Applicant, who will then have the option to withdraw the question. If the Applicant continues to request a response to that question, the question and the response may be provided to all Applicants (subject to the second point above).

[23] Financial Close is achieved when all project contracts are signed and all required funding irrevocably committed. It is expected to be achieved within 4 months of ARENA making an offer of funding (following ARENA Board approval)

the range of proposals received. Data to be published on the winning bids at the conclusion of the Full Application stage include:

- Total Project Cost (in aggregate and by key component) per MW (DC/AC);
- LCOE (AUS$/MWh);
- ARENA grant funding amount per MWh of Estimated Net Generation;
- ARENA grant as a percentage of Total Project Cost;
- Project details and metrics by geographic (State/Territory) location;
- PPA pricing and term;
- Debt and equity financing ratios; and
- Expected levels of return.

No material change permission

To ensure fairness in assessment, no material change to the Proposal will be permitted between the EOI and Full Application stages. A material change would include but is not limited to:

- a change in the location of the project (excludes micro-siting);
- a change of more than 10% in the rated (AC) capacity of the project; and
- an increase of more than 5% in the LCOE of the project.[24]

Similarly, no change to project location or size will be permitted between the Full Application and Financial Close, and an LCOE threshold will apply.[25] Resubmission of EOIs or revised proposals will not be accepted.

No bilateral negotiation

ARENA specified that it would not enter into any bilateral negotiations with bidders in the solar PV procurement process.

Partial cost rebate

A total of up to AUS$2 million will be available to compensate unsuccessful applicants for costs incurred during the application process subject to certain eligibility requirements. The partial cost

[24] This LCOE will be adjusted for changes in foreign exchange rates from 9 September 2015 to 1 June 2016 based on the foreign currency denominated components nominated as part of your EOI stage Application.

[25] No more than 5% above the project's LCOE specified in the EOI.

rebate will cover up to 50% of verifiable third party costs incurred in the development of the proposal from the commencement of the EOI subject to a maximum of AUS$250,000 for each unsuccessful applicant and the funds available.

4.3 Transmission

Transmission costs are required to be included in the calculation of the LCOE which are used as a threshold criterion in evaluating applications.[26]

According to the National Electricity Rules[27] and the rule change document from AEMC,[28] the enquiring generator usually bears the standalone transmission costs specified in the connection offer, although the costs could be shared by government/network service provider ("NSP")/third party as a result of bilateral negotiation. The investment for transmission expansion could also be made if an entity (a transmission network service provider/generator/government/third party) is willing to fund the Scale Efficient Network Extensions ("SENE") and bear the asset stranding risk.

Accordingly, during the procurement process, the estimated transmission (including augmentation) costs will be included in the cost calculation in the application. ARENA's funding may thus partially and indirectly contribute to covering the cost of some transmission expansion. The winning projects might also be able to negotiate with NSP or the government to split related costs and the compensation funding from ARENA, but these are not guaranteed and occur on a case-by-case basis.

4.4 Outcomes

22 high merit projects have been selected to proceed to the full application stage.

---

[26] There is a standardized template for cost calculation designed for this competitive round accessed through ARENA's website <http://arena.gov.au/files/2015/10/LCOE-calculator.xlsx>

[27] AEMC. "*National Electricity Rules*." <http://www.aemc.gov.au/getattachment/a7fb8f95-ce47-4912-952d-4138e8d351ce/National-Electricity-Rules-Version-78.aspx>

[28] AEMC. "*National Electricity Amendment (Scale Efficient Network Extensions) Rule 2011*". June 30, 2011. <http://www.aemc.gov.au/getattachment/6073134e-f3de-4af8-8ac9-855f6866897a/Final-Rule-Determination.aspx>

Figure 12. 22 short-listed projects invited to submit a Full Application

Organisation	Project	Town	State	MW
Origin Energy Limited	Darling Downs Solar Farm	Dalby	QLD	107
Gannawarra Solar Farm Pty Ltd	Gannawarra Solar Farm	Kerang	VIC	53
Syncline Energy Pty Ltd	Bannerton Solar Park	Bannerton	VIC	51
FRV Services Australia Pty Ltd	Baralaba Solar Farm	Baralaba	QLD	50
Genex Power Limited	Kidston Solar Project	Kidston	QLD	50
KCSF Consortium	North Queensland Solar Farm	Proserpine	QLD	50
Neoen Australia Pty Ltd	Parkes Solar Farm	Parkes	NSW	46
Infigen Energy	Manildra Solar Farm	Manildra	NSW	42
RATCH-Australia Corporation Limited	Collinsville Solar Power Station	Collinsville	QLD	42
Infigen Energy	Capital Solar Farm	Bungendore	NSW	39
SF Suntech Australia Pty Ltd	Griffith Solar Farm	Griffith	NSW	34
Neoen Australia Pty Ltd	Griffith Solar Farm	Griffith	NSW	26
Canadian Solar (Australia) Pty Ltd	Oakey Solar Farm	Oakey	QLD	25
Neoen Australia Pty Ltd	Dubbo Solar Hub	Dubbo	NSW	22
APA Group	Emu Downs Solar Farm	Cervantes	WA	20
Goldwind Australia Pty Ltd	White Rock Solar Farm	Glen Innes	NSW	20
Kennedy Energy Park Pty Ltd	Kennedy Energy Park	Hughenden	QLD	19
Lyon Infrastructure Investments Pty Ltd	Kingfisher solar storage project	Far northern South Australia	SA	17
Canadian Solar (Australia) Pty Ltd	Longreach Solar Farm	Longreach	QLD	15
Overland Sun Farming Company Pty Ltd	Hughenden Sun Farm	Hughenden	QLD	14
EPHO Pty Ltd	Gidginbung Solar Farm	Temora	NSW	12
juwi Renewable Energy Pty Ltd	Ebenezer Solar Project	Ipswich	QLD	10

These projects are located in all mainland states and have a total capacity of 766 MW. Full applications are due by June 15, 2016. The ARENA Board plans to announce winning bidders by August/September of 2016.

4.5 Strengths and weaknesses

Since the first competitive round is still in process, there are not many evaluations of ARENA's approach. However, the following characteristics appear to be strengths of ARENA's approach:

- use of a standardized LCOE calculation template for all applicants to a large extent makes the bidding cost of proposed projects more comparable;
- ARENA assesses the financial viability of proposals by requiring offtake agreements and evaluating the quality of the implementation plan along with the proposal, including the risk management, the workplace health and safety plan, key milestones and delivery approach;
- no material change and resubmission permission increases the fairness of the proposal evaluation; and
- partial cost rebate encourages more applicants to participate, which enhances the competitiveness of the procurement.

To improve on the past solar flagships program, the current solar large-scale PV competitive round puts stricter requirements on the financial viability and co-funding commitments to reduce the chance of future failures caused by lack of funding. This process also includes more advanced competition design than required in the solar flagship process.

The weaknesses of ARENA's approach include:

- the merit criteria are relatively subjective and it is not clear how they are quantified as part of the bid evaluation process;
- there does not appear to be any third party oversight of the process; and
- ARENA is a relatively new institution; its procurement expertise is not yet proven.

4.6 Implications for Alberta

- The single technology focus in this procurement is somewhat anomalous. This is driven by unique circumstances in Australia (i.e., the desire to figure out how to deploy large scale solar more cost effectively) that are not likely to be applicable to other markets such as Alberta.
- However, ARENA's explicitly stated objective of decreasing the cost of solar and its allocation of significant funds to that objective is likely to have an impact. To the extent that Alberta has similar specific targeted objectives, it may consider using ARENA's clear and explicit communication approach.
- ARENA is using a particularly transparent approach in its efforts to drive down price. It is hoping that by sharing significant (but anonymized) bid data it will help foster a competitive dynamic which will serve as an impetus for reducing prices. While some of that data sharing will be useful, it is unclear how comfortable developers will be releasing all of the statistics, especially ones on financing and returns.
- However, the lack of third party oversight to ARENA's process is a weakness. While ARENA is ostensibly a neutral participant, these processes are always helped by some degree of external oversight, if for nothing more than some constructive feedback on ways to improve the process next time.

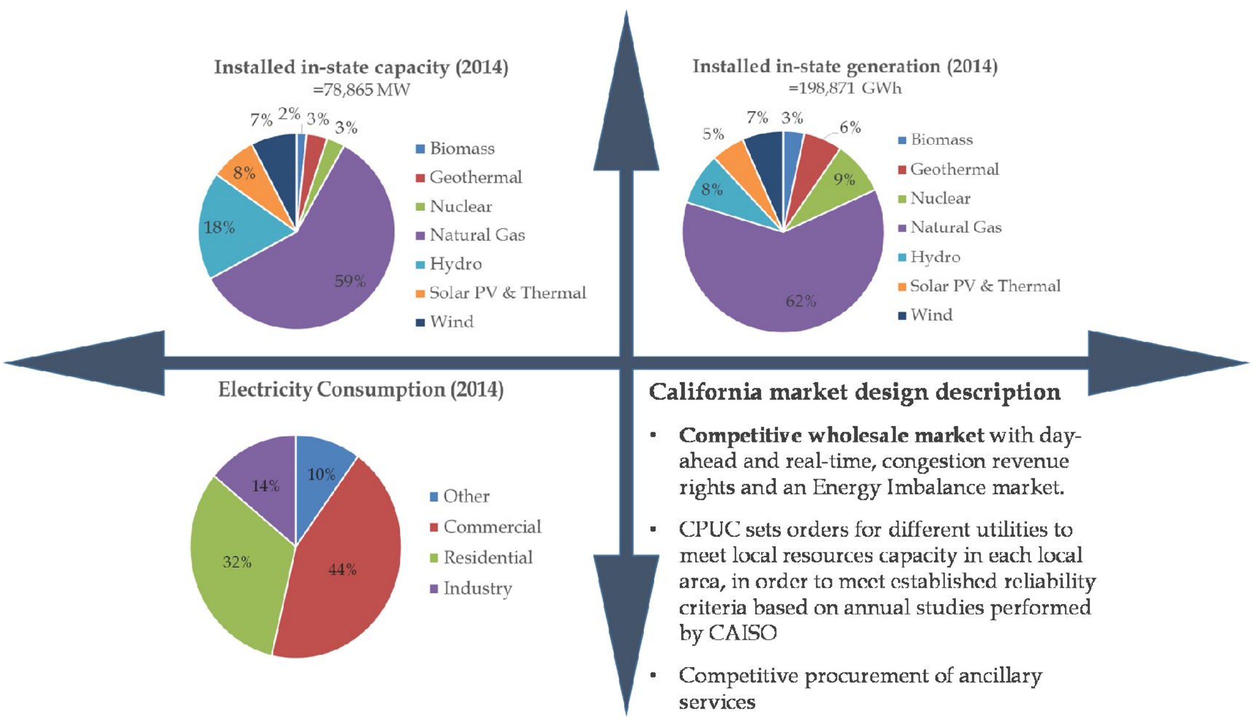
5 California RPS procurement program

5.1 Context

5.1.1 California market characteristics

California has an installed capacity of almost 79,000 MW, which generates the bulk of its electricity using mainly natural gas. Coal represents a negligible portion of both installed capacity (0.002%) and generation (0.005%) due to California's efforts to eliminate the consumption of coal-fired power in the state. California's electricity consumption is balanced between its different customer segments with 14% from industrial load.

Figure 13. Overview of California electric power market characteristics



Note: 'Other' in the electricity consumption graphic represents consumption by water pumps, mining & construction and streetlights.

Source: EIA, California Energy Commission ("CEC"), CPUC

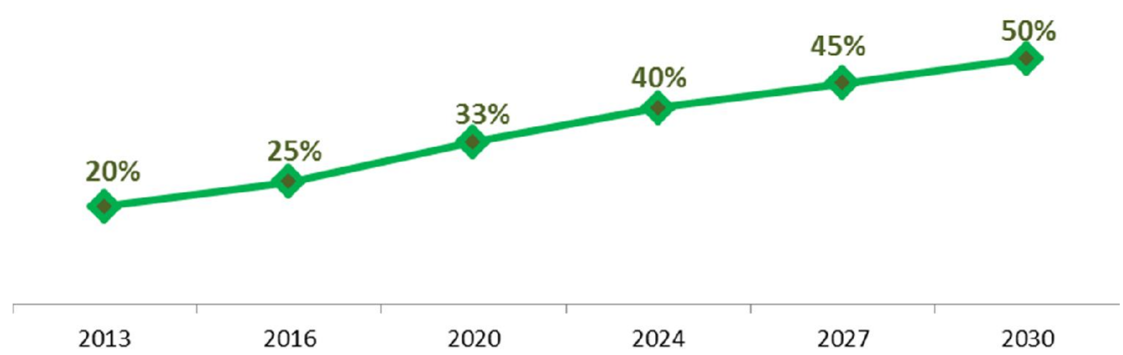
The California Independent System Operator ("CAISO") operates the power grid and wholesale electricity market in about 80% of California. The remainder of California is operated by local balancing authorities and utilities, such as the Los Angeles Department of Water and Power ("LADWP") and the Sacramento Municipal Utility District ("SMUD").[29]

The three investor owned utilities ("IOUs") in California that cover a majority of the electric service area are Pacific Gas and Electric Company ("PG&E"), San Diego Gas and Electric ("SDG&E"), and Southern California Edison ("SCE"). This case study will focus primarily on these entities, and the renewable procurement programs managed by them.

5.1.2 California renewable energy targets

California's RPS was originally established by legislation enacted in 2002. Subsequent amendments to the law, such as the SB 350 legislation that came into effect on October 7, 2015, have resulted in a requirement for California's electric utilities to have 50% of their retail sales derived from eligible renewable energy resources by 2030. The law established interim targets for the utilities as shown below that are applicable to all IOUs and Publicly Owned Municipal Utilities ("POUs"). The latter are not regulated by the CPUC, but are subject to the legislation in and their governing boards are charged with establishing procurement requirements based on the interim goals in Figure 14 below.[30]

Figure 14. California RPS interim targets



Note: The deadlines to meet RPS interim targets are on December 31 of each of these years.
Source: EIA, California Energy Commission ("CEC"), CPUC

The primary procurement mechanism for the California RPS program in the Utility Scale Request for Offers ("RFO"), which is conducted by the IOUs and overseen by CPUC. The second key method of procurement of renewable resources is through the Renewables Auction Mechanism ("RAM") Program, which is a centralized and expedited program that the IOUs may use to satisfy authorized procurement needs. IOU Solar PV programs have also been implemented whereby

---

[29] California Energy Commission. *"Map of Balancing Authority Areas in California."* November 22, 2013. <http://www.energy.ca.gov/maps/serviceareas/balancing_authority.html>. Note: The Sacramento Municipal Utility District joined the Balancing Authority of Northern California, Valley Electric Association joined the CAISO, and Bonneville Power Administration is now included under the PacifiCorp-West balancing area.

[30] California Public Utilities Commission. *California Renewables Portfolio Standard.* Accessed February 29, 2016. <http://www.cpuc.ca.gov/RPS_Homepage/>

PG&E, SCE and SDG&E may own and operate solar PV facilities, as well as execute solar PV power purchase agreements with independent power producers ("IPP") through a competitive solicitation process. California also runs two feed in tariff ("FIT") programs, namely the Renewable FIT program and the Bioenergy FIT program. This case study focuses on the RFO and RAM programs, which are good examples of a competitive procurement process.

5.2 Key process design attributes

The CPUC and the CEC jointly implement the RPS program and the procurement programs that support RPS goals. Figure 15 below provides more details on the energy entities within California and their respective duties.

Figure 15. Energy entities within California and their responsibilities

Agency	Primary Responsibilities
CPUC	1) Regulates privately owned electric, natural gas, telecommunications, water, railroad, rail transit, and passenger transportation companies 2) Responsible for determining annual procurement targets and enforcing compliance 3) Reviews and approves each IOU's renewable energy procurement plan 4) Reviews IOU contracts for RPS-eligible energy and establishes the standard terms and conditions used by IOUs in their contracts for eligible renewable energy
CEC	1) Forecasts future energy needs 2) Promotes energy efficiency and conservation by setting the state's appliance and building energy efficiency standards 3) Supports energy research that advances energy science and technology 4) Develops renewable energy resources and jointly implementing the RPS with the CPUC 5) Advances alternative and renewable transportation fuels and technologies 6) Certifees thermal power plants 50 MW and larger 7) Plans for and directs state response to energy emergencies
CAISO	1) Provides open and non-discriminatory access to the bulk of the state's wholesale transmission grid, supported by a competitive energy market and comprehensive planning efforts 2) Carries out reliability studies to determine the capacity requirement in local geographic areas
WECC	1) Enforces compliance and mandaatory reliability standards approved by FERC 2) Identifies future transmissions system needs under a variety of possible energy futures for use in long-term planning, as well as conducts studies on resource adequacy
IOUs	1) Privately owned electricity and natural gas providers for customers within California 2) Purchase power through contracts and operate their own generation facilities 3) Customer rates are set through the CPUC

Source: CEC, CPUC, CAISO, WECC

The CPUC is responsible for determining annual procurement targets and enforcing compliance, as well as reviewing and approving each IOU's renewable energy procurement plan. The CPUC also reviews IOU contracts for RPS-eligible energy and establishes the standard terms and conditions used by IOUs in their contracts for eligible renewable energy.

Overview of California's IOU RFO program:

- Primary RPS procurement mechanism in the state
- Run annually by individual IOUs to procure eligible resources (>0.5 MW) in WECC
- Approximately 500 days from issue of RFO
- Oversight provided by the CPUC and an independent evaluator; shortlist discussed with a Procurement Review Group
- Offered projects assessed based on pre-determined criteria and weighing mechanism
- Projects connecting to existing and/or proposed transmission given preference

5.2.1 Establishing resources needs

The ***Utility Scale Request for Offers*** is the primary procurement mechanism for the California RPS program. The IOUs' utility-scale solicitations or RFOs are competitive processes conducted by the IOUs and overseen by the CPUC and an Independent Evaluator. The percentage target is laid out in legislation so the utilities are simply working to those goals. At the beginning of each annual RPS solicitation cycle, each IOU submits its RPS procurement plan and solicitation protocol (which is essentially an RFP), as well as a detailed description of the IOU's least-cost best-fit methodology to the CPUC for approval. The RPS statute requires utilities to select renewable resources that are least-cost and best-fit. Costs including the cost of the renewable energy generation as well as any indirect costs due integration of the resource and needed transmission investment. Benefits include the value of energy, capacity, and ancillary services to the system. The "best fit" criteria refers to how well the project meets the utility's specific system needs and RPS portfolio needs.

Overview of California's RAM program:

- Simplified process for smaller renewable generation projects
- 6 RAM auctions have been held so far by each of the three large IOUs
- Auction mechanism chooses least-cost projects until the MW to be procured have been fulfilled; contracts will be subject to CPUC approval
- RAM procurement process takes approximately 6 months
- IOUs can decide whether or not they need to hold a RAM auction

Offers may be from any eligible renewable resource located within the Western Electricity Coordinating Council ("WECC") that has a capacity of 0.5 MW or greater. The CEC defines eligible renewable energy resources by renewable resource or fuel, rather than by the specific technology used. For certain eligible renewable energy resources, however, the CEC considers both the resource or fuel and the technology to determine RPS eligibility for the facility that uses them for electricity generation. Eligible fuel sources currently include biodiesel, biomass, biomethane, fuel cells using renewable fuels, geothermal, hydroelectric, municipal solid waste, ocean thermal and wave, solar, wind and tidal current. The CEC has published a guidebook to 'Renewable Portfolio Standard Eligibility' that provides further details on any additional eligibility criteria for resource offers.[31] California also integrates several non-economic criteria into its overall assessment of proposals, such as contribution to RPS goals and supplier diversity, but how these are considered is not detailed and they do not appear to be integrated into the assessment of financial bids.

In 2010, the CPUC adopted the ***RAM program*** to create a simplified market-based procurement process for smaller RPS generation projects greater than 3 MW and up to 20 MW.[32] The CPUC initially authorized the utilities to procure 1,000 MW across all three IOUs (later expanded to 1,299 MW) through the RAM by holding four auctions over two years. A fifth auction was authorized by Resolution E-4582 to take place no later than a year after the close of the 4th RAM auction. One additional RAM auction, RAM 6, was authorized and was completed in 2015. Future RAM auctions may be held depending on utility needs.[33] The revised RAM program does not have mandated procurement targets but instead allows the IOUs to determine the need for a RAM solicitation to meet a CPUC authorized need or any need arising from legislative mandates. The revised RAM does not limit the geographic location of projects to the service territory of the three IOUs but instead expands the geographic location to the entire CAISO control area and also includes resources that can be dynamically scheduled into the CAISO. The RAM procurement is largely price focused but extra credit is given to projects located in environmental justice communities (which are listed in the RFP) or located in load centers.

5.2.2 Managing procurement process

The RFO and RAM programs are very similar among different utilities; however, there are some minor differences in each utility's individual programs. The CPUC is primarily responsible for overseeing these programs and for approving acceptance final bids and contracts. In the interest of clarity, we have used one utility (PG&E) as an example to illustrate how these programs are implemented in detail.

Each IOU within California runs their own ***RFO procurement*** on an annual basis, procuring the energy commodity and renewable energy credits ("REC") associated with it. There are several key phases to the RFO process:[34]

- The IOU files its draft RPS procurement plan, including a solicitation protocol, with the CPUC; the CPUC reviews the plan and stakeholder feedback and then issues a decision conditionally accepting the plan.

---

[31] California Public Utilities Commission. *Utility Scale Request for Offers.* Accessed February 29, 2016. <http://www.cpuc.ca.gov/Utility_Scale_RFO/>

[32] The revised RAM program does not cap projects at 20 MW but allows the IOUs to determine the optimal maximum project size for any procurement targeted through RAM.

[33] California Public Utilities Commission. *Renewable Auction Mechanism.* Accessed February 29, 2016. < http://www.cpuc.ca.gov/Renewable_Auction_Mechanism/>

[34] California Public Utilities Commission. *Utility Scale Request for Offers.* Accessed February 29, 2016. < http://www.cpuc.ca.gov/Utility_Scale_RFO/>

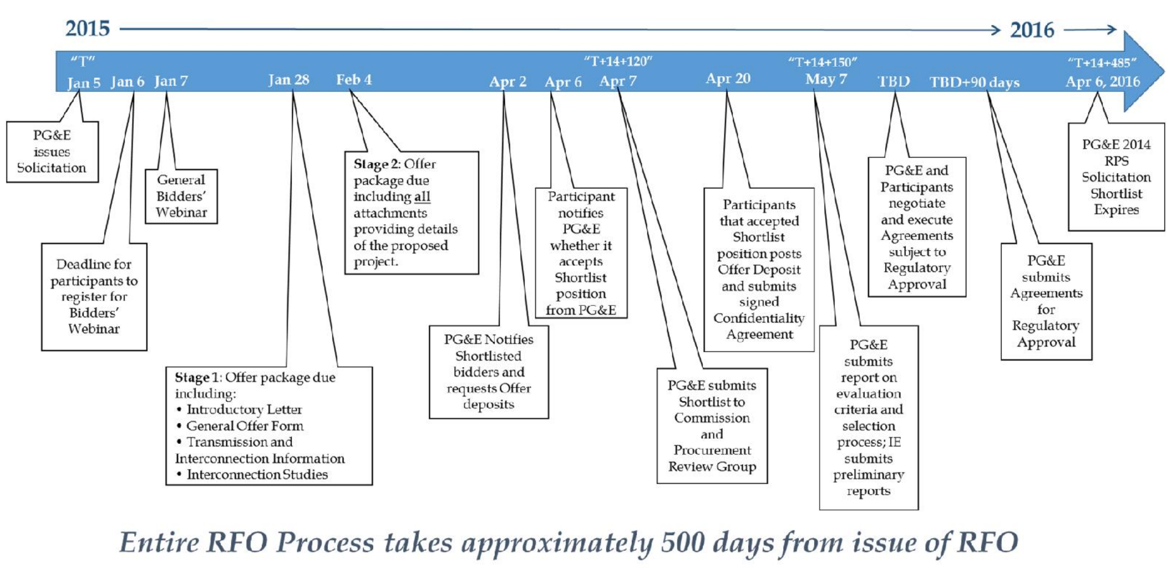
- Following CPUC approval of its RPS procurement plan and solicitation protocol, an IOU can initiate its RPS solicitation. The entire solicitation is overseen by the CPUC and an independent evaluator. Interested respondents file notices and respondents submit their offers to bid according to the IOU's solicitation schedule.

- The IOU evaluates all of the offers to ensure conformance with solicitation requirements and uses its "least-cost, best-fit" evaluation process (as discussed in Section 5.2.1) to rank offers by value to develop a "shortlist" of offers. The IOU then reviews its proposed shortlist with its Procurement Review Group ("PRG"), after which it requests CPUC approval of its final shortlist. The independent evaluator provides its opinion regarding the fairness and robustness of the utility's solicitation process and results to the CPUC. The IOU and shortlisted bidders then negotiate contract terms.

- The IOU files an application requesting approval of a contract with the CPUC, which includes the final independent evaluator report regarding the proposed contract. The CPUC reviews the submitted contracts for cost reasonableness, consistency with rules, and safety, as well as any protests, responses, or replies to the application. The CPUC then approves, approves with modification, or rejects the RPS contract.

Figure 16 displayed below shows PG&E's 2014 solicitation schedule, which lasted approximately 15 months. Each IOU's solicitation schedule follows a similar pattern; however, specific dates vary across utilities. The expiration date of the RPS shortlist sets the outer limit of the RFO procurement process.

Figure 16. PG&E 2014 RPS Solicitation Schedule under the RFO program



Source: PG&E 2014 Solicitation Protocol

As described in the preceding section, the ***RAM program*** has been modified to add flexibility with respect to the MW size of the bids, the frequency of the auction, and the location of the projects. IOUs must explain in their annual RPS procurement plan filings how any proposed RAM could satisfy an authorized procurement need. The CPUC then approves whether or not RAM procurement shall occur and the frequency of these procurements. The RAM procurement is characterized by a standard non-negotiable contract and a standardized valuation process. The CPUC has tweaked the RAM process following each auction in order to optimize the process and to allow more flexibility with the procurements.

Each utility must develop its own standard RAM contract, which contains a few standard terms and conditions, including:

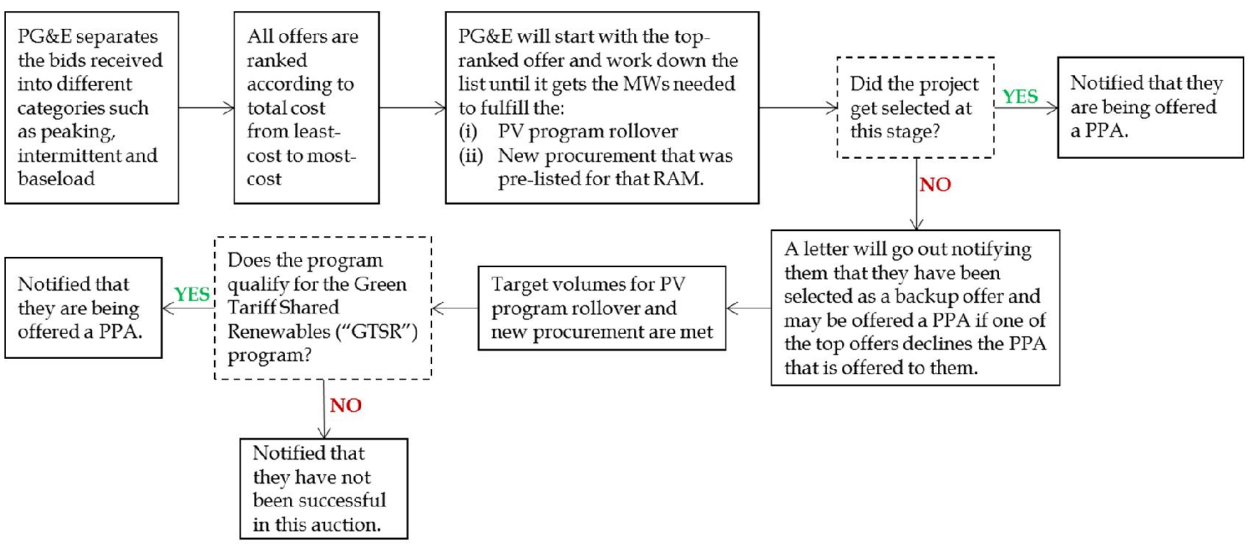
- Project must go through an interconnection study, be online within 36 months of contract execution, with one allowable six-month extension for regulatory delays.

- The development deposit for projects 5 MW and smaller is US$20/kW. For projects that are between five and 20 MW, a US$60/kW or US$90/kW development deposit is required for intermittent and baseload resources, respectively. Delivery terms (10, 15, or 20 years) are specified.

- The development deposit is converted to a performance deposit for projects smaller than five MW. For projects at least five MW, it is 5% of expected total project revenues.

Market-based pricing is used in this program, and sellers compete for a contract in the RAM. Bids are selected by least-cost price first, until the auction capacity is reached. The price and contract is not negotiable and is paid as bid.

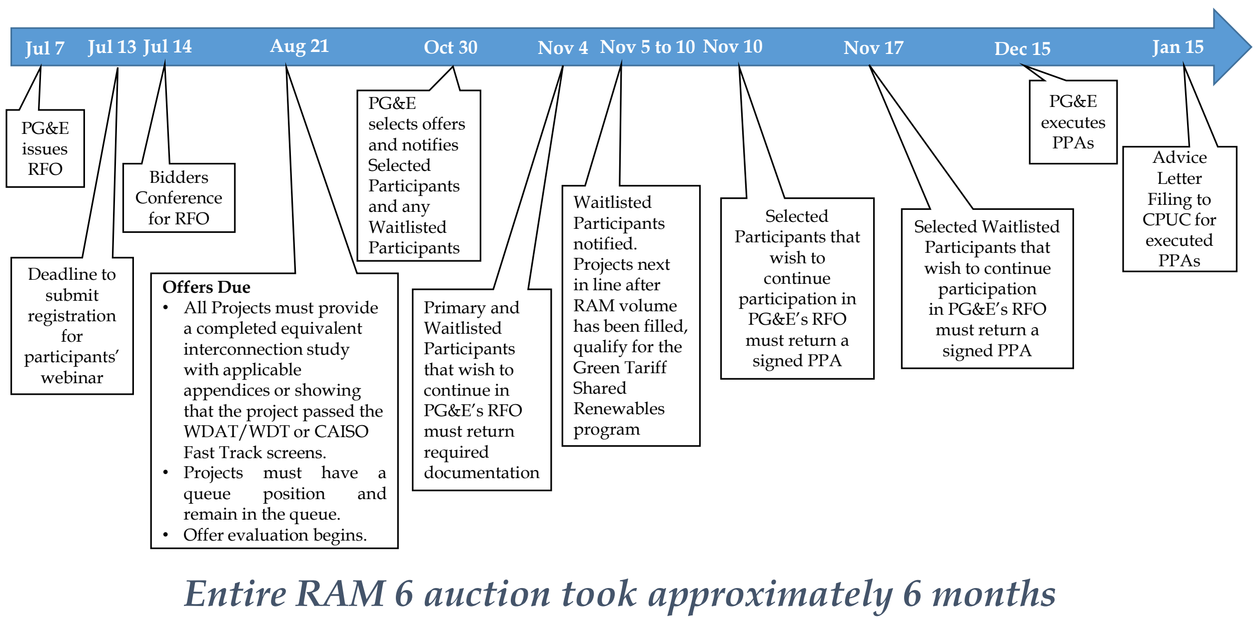
Figure 17. PG&E 2014 RAM 6 schedule



Source: Pacific Gas and Electric Company Renewable Auction Mechanism Request for Offers (RAM 6).

Eligibility of the project is evaluated first; ineligible project bids are not considered in RAM auctions. The project must be in the CAISO balancing area or dynamically scheduled into the CAISO, offer 100% site control through: (i) direct ownership; (ii) lease; or (iii) an option to lease or purchase that may be exercised upon award of a RAM contract. Another requirement is that at least one member of the development team for the project must have (i) completed at least one project of similar technology and capacity or (ii) begun construction of at least one other similar project. The project should also be based on an already commercialized technology and an interconnection application should already be filed prior to bidding into the RAM.[35] Figure 17 depicts the RAM auction process for PG&E in the form of a flowchart of actions. Figure **18** below outlines the most recent auction schedule (RAM 6) for PG&E that closed on August 21, 2015.

Figure 18. **PG&E 2014 RAM 6 schedule**



Source: PG&E RAM 6 schedule

5.2.3 Ensuring competitive outcomes

This section will address the oversight of the procurement process, the bid evaluation processes, and other factors that ensure a competitive outcome for California's renewable procurements.[36]

There are several ways that the competitive nature of the RFO process is ensured. The IOUs are required to consider the viability of renewable projects when evaluating the value, costs, and benefits of offers received through solicitations and bilaterally. The Energy Division staff of the CEC developed a Project Viability Calculator ("PVC") with stakeholder participation from utilities, renewable project developers, and ratepayer advocates. The PVC is a tool for the utilities to evaluate the viability of a renewable energy project, relative to other projects that bid into the California utilities' RFOs. The PVC uses standardized categories and criteria to quantify a

---

35 California Public Utilities Commission. *Renewable Auction Mechanism.* Accessed February 29, 2016. <http://www.cpuc.ca.gov/Renewable_Auction_Mechanism/>

36 California Public Utilities Commission. *RPS Program Overview.* Accessed February 29, 2016. <http://www.cpuc.ca.gov/RPS_Homepage/>

project's strengths and weaknesses in key areas of renewable project development. The PVC is not a tool to determine the exact merit of a particular project or contract, but is used as a screening and ranking tool.[37] Figure 19 outlines the criteria scoring guideline used in the PVC.

Figure 19. Criteria and sample scoring guideline for the RFO Project Viability Calculator

Category	Criteria	Weight	Sample scoring guideline (Score of 10/10)
Company/Development Team	Project Development Experience	4	The company and/or the development team has completed 2+ projects of similar technology and similar or larger capacity.
	Ownership/O&M Experience	1	The company, development team or subcontractor has experience with 2 or more projects of similar technology and capacity.
Technology	Technical Feasibility	4	Project will use commercialized technology or commercialized technology that is nearly identical.
	Resource Quality	2	Bidder demonstrated that the resource can support the production profile.
	Manufacturing Supply Chain	3	There are no known or anticipated supply chain constraints.
Development Milestones	Site Control	4	Project has 100% site control for the project site and gen-tie line corridor connecting the facility to the grid.
	Permitting Status	4	Project has received its Conditional Use Permit (CUP), Application for Certification (AFC), Record of Decision from the BLM or equivalent federal agency.
	Project Financing Status	4	The bidder demonstrated that project financing has been secured either through "balance sheet" financing or power purchase agreement (PPA) financing.
	Interconnection Progress	4	The project has executed its Interconnection Agreement.
	Transmission Requirements	3	No transmission system upgrades are required for the project pursuant to the most recent interconnection study, or the project has passed the Fast Track screens.
	Reasonableness of COD	3	Utility reasonably expects the project will achieve its COD.

Source: CPUC

The quantitative assessment of bids focuses on two key elements. The first is the Market Valuation of the bid, which is calculated by subtracting the PPA price, any transmission upgrade costs, congestion costs, and integration costs from the value of the project's energy, capacity and ancillary services. The second element is the portfolio adjusted value, which factors in the project's location, how well it meets the utility's RPS needs, how firm the energy supply is, and the level of curtailment the project can offer.

California does not use a not to exceed cap in its quantitative bid evaluation but does try to contain costs for RPS procurement. For the RFOs, each project is compared to a market price referent ("MPR"). The MPR for a project is determined by estimating the costs of a comparable virtual proxy plant. If bids are above that level, the utilities have to seek approval for the contract and the recovery of any above-MPR contract costs from the CPUC. Costs for above MPR level costs are limited.

---

[37] California Public Utilities Commission. *Utility Scale Request for Offers*. Accessed February 29, 2016. <http://www.cpuc.ca.gov/RPS_Overview/>

The CPUC also requires each IOU to establish a PRG whose non-market participants, subject to an appropriate non-disclosure agreement, have the right to consult with the utility and review the details of the utilities' overall procurement strategy, proposed procurement processes, and proposed procurement contracts. PRG participants include the California Department of Water Resources ("DWR"), the CEC's Energy Division, the Union of Concerned Scientists ("UCS"), the Division of Ratepayer Advocates ("DRA"), the Coalition of California Utility Employees ("CUE"), and The Utility Reform Network ("TURN"). Although the CPUC Energy Division is a member of the PRG, it does not formally provide its determination until the end of the process.

The CPUC requires an independent evaluator ("IE") for each RPS solicitation under the utility scale RFO program, in order to ensure that the process is fair. The IE provides third party oversight of the RPS procurement process. At the conclusion of the solicitation, the IE writes a report which is submitted via the IOU to the CPUC providing a critical assessment of the robustness of the solicitation, the effectiveness of the least-cost best-fit methodology, and a determination of whether that methodology was fairly administered. The IE also completes a contract-specific report whenever an offer from a solicitation is submitted as a contract to the Commission.

In addition, the RFOs require both bid deposits (set at US$3/kW once the project has been shortlisted) and contract security, which is set at US$15/kW until the CPUC approves the contract, at which point it increases to US$60/kW for intermittent projects and US$90/kW for baseload projects.

The ***RAM procurement program*** has a simpler and more straightforward mechanism as it was designed to expedite the procurement of renewable resources. This auction mechanism is designed to be competitive in nature, as the projects are selected based mainly on price. This is intended to drive the cost of renewable procurement down and make the RPS goal achievement more economical. The process is also overseen by the CPUC and only eligible offers (according to a pre-determined standard) are considered, making the procurement standardized and fair to all participants. To ensure security of delivery of renewable resources in RAM, development deposits and performance deposits are collected prior to issuing PPAs, as mentioned in Section 5.2.2. A delivery term security equal to 5% of expected total project revenues is also required for all projects except those under the GTSR program with a contract capacity of less than 3 MW. The security amount is equal to 6 months of revenue for a 10 year PPA, 9 months of revenue for a 15 year PPA, or 12 months of revenue for a 20 year PPA; the amount is due on the commercial operation date.

5.3 Transmission

Prior to 2012, the development of electricity transmission lines and facilities in California occurred in a bottom-up fashion where energy project developers would choose where to site their projects, and then transmission followed. However, at one point, the capacity of renewable projects in the CAISO interconnection queue exceeded California's entire forecasted load in 2020 and, thus, far exceeded the amount of new capacity needed for the IOUs to meet their 33% renewable obligation by 2020. Recognizing that most proposed renewable projects would never be built, the CPUC passed a decision that would promote the development of cost-effective and location-appropriate transmission first and encourage renewable resources to develop near existing and proposed transmission.[38]

Many of the proposed projects awaiting interconnection prior to 2012 required costly delivery network upgrades, which would ultimately be borne by ratepayers. Accordingly, the CAISO also adapted its procedures to ensure that transmission development focused on high value projects. The CPUC limited the total capacity of RPS procurement to the CAISO-determined threshold for each geographic area. If an IOU collectively proposed to procure more than this threshold, the CPUC would determine which projects' contracts could be approved based on project need, viability and value.[39]

When carrying out RFOs for procurements of renewable resource to meet RPS targets, IOUs may include preferences for projects in areas with approved transmission lines. Interconnection progress is one of the criteria that proposals are evaluated on in the utility scale RFO, as part of the Project Viability Calculator. For the RAM auctions, one of the prerequisite conditions to be eligible for participation is that the geographic location of projects should be within the CAISO control area or could be dynamically scheduled into the CAISO. Interconnection studies are required for both of these programs, and the costs associated with interconnection of a project to the network is included in the proposal.

PG&E's Electric Rule No. 21 regarding generating facility interconnections specifically states: *"An Applicant, or a Producer where those are different entities, is responsible for all fees and/or costs, including Commissioning Testing, required to complete the interconnection process. A Producer that interconnects to Distribution Provider's Distribution or Transmission System is responsible for all costs associated with Parallel Operation to support the safe and reliable operation of the Distribution and Transmission System."* LEI notes, however, that this interconnection cost, when included in the proposed price, is eventually realized by the ratepayers under the IOU that contracts the specified project linked to a transmission build.[40]

5.4 Outcomes

The CPUC is required to report quarterly to the state legislature on IOU progress toward their RPS goals and substantive actions taken to achieve those goals. There are 125 renewable projects with a total capacity of 11,240 MW resulting from the various RPS procurements that are approved and operational. Approved sale contracts include seven projects with a minimum expected generation of approximately 1,703 GWh annually. An additional 45 projects with approximately 3,609 MW of capacity have currently been approved through RPS procurement processes and are currently in development. Lastly, seven contracts totaling 1,148 MW in capacity are pending approval by the CPUC and CEC.[41]

---

[38] California Public Utilities Commission. *Rulemaking 11-05-005*. May 5, 2011.

[39] Ibid.

[40] Pacific Gas and Electric Company. *Electric Rule No. 21.* January 21, 2015.

[41] California Public Utilities Commission. *Monthly RPS project status table.* Accessed February 29, 2016.

Information on utility-scale RFO processes is only available in aggregated formats from CEC and CPUC reports, as shown in the table below. Prices are not announced for winning RFO bidders so the only indication of RFO costs in California comes from the aggregated data, which shows that overall RPS compliance costs in 2014 (the latest year available) ranged from US$92-US$107/MWh. (These prices reflect additional federal level fiscal incentives.) Figure 20 lists the compliance progress and cost information; along with a forecasted 2020 RPS status for the three large IOUs within California.

Figure 20. IOU RPS Compliance Progress and Cost Information, 2005-2014

	Name of Retail Seller	2014 Retail Sales	2014 RPS Procurement	2014 RPS Procurement %	2020 Retail Sales	2020 RPS Procurement	2020 RPS Procurement %
Large IOU	PG&E	74,546	20,894	28.0%	59,668	22,051	37.0%
	SCE	75,828	17,618	23.2%	74,687	27,529	36.9%
	SDGE	16,467	6,002	36.4%	16,726	7,209	43.1%

IOU	Data Input	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014
PG&E	Retail Sales (GWh)	72,372	76,356	79,078	81,524	79,624	77,485	74,864	76,205	75,705	75,546
	RPS Generation (GWh)	8,908	9,080	9,034	9,824	11,497	12,359	13,920	15,131	17,652	20,894
	RPS Procurement (%)	12.3%	11.9%	11.4%	12.1%	14.4%	16.0%	18.6%	19.3%	23.3%	28.0%
	RPS Expenditures ($, thousands)	551,874	575,483	671,371	790,116	791,870	893,010	1,017,030	1,198,832	1,662,654	2,237,594
	RPS Costs (dollars per MWh)	61.95	63.38	74.31	80.42	68.88	72.26	73.06	79.23	94.19	107.09
SCE	Retail Sales (GWh)	74,994	78,863	79,505	80,956	78,048	75,141	73,778	75,597	74,480	75,828
	RPS Generation (GWh)	12,715	12,382	12,163	12,291	13,034	14,344	15,171	14,992	16,444	17,618
	RPS Procurement (%)	17.0%	15.7%	15.3%	15.2%	16.7%	19.1%	20.6%	19.8%	22.1%	23.2%
	RPS Expenditures ($, thousands)	968,003	932,421	976,870	1,138,145	1,032,716	1,172,088	1,299,941	1,230,432	1,436,844	1,630,892
	RPS Costs (dollars per MWh)	76.13	75.30	80.31	92.60	79.23	81.71	85.68	82.07	87.38	92.57
SDGE	Retail Sales (GWh)	16,002	16,847	17,056	17,410	16,994	16,283	16,249	16,627	16,164	16,467
	RPS Generation (GWh)	825	900	881	1,047	1,784	1,940	3,380	3,416	4,702	6,002
	RPS Procurement (%)	5.2%	5.3%	5.2%	6.0%	10.5%	11.9%	20.8%	20.5%	29.0%	36.4%
	RPS Expenditures ($, thousands)	40,219	44,832	42,886	55,726	95,965	109,275	142,866	256,245	362,556	563,468
	RPS Costs (dollars per MWh)	48.73	49.84	48.69	53.20	53.78	56.34	42.27	75.01	77.09	93.87

Source: CPUC - Biennial RPS Program Update in Compliance with Public Utilities Code Section 913.6

More granular information is available on the six ***RAM auctions***. The first RAM auction closed on November 15, 2011, with the CPUC approving 13 contracts for 140 MW. The second RAM auction closed on May 31, 2012, with the CPUC approving 17 contracts for 255 MW. The third RAM auction closed on December 21, 2012, with the CPUC approving 21 contracts for 337 MW. The fourth RAM auction closed on June 28, 2013, with the CPUC approving 17 contracts for 239 MW. The fifth RAM auction closed on June 27, 2015, with the CPUC approving 29 contracts for a total 417.7 MW. An example, providing a summary of solicitation selection for PG&E's fifth RAM auction is shown in Figure 21. Prices in those auctions are not released publicly.

Figure 21. Summary of solicitation selection for PG&E's fifth RAM auction

Seller	Technology	Capacity (MW)	Location	Est. Annual Deliveries (GWh)	Commercial Operation Date (COD)	Term (years)
Rising Tree Wind Farm II LLC	Wind	19.8	Mejave	68.9	3/31/2015	20
STS Hydropower, Ltd.	Hydro	5.5	Zenia	13.3	Existing Facility	20
87RL 8MW LLC	Solar PV	15	Kern	32.9	11/2/2015	20
Three Rocks Solar, LLC	Solar PV	13	Three Rocks	33.4	11/2/2015	20

Source: Pacific Gas and Electric Company Advice Letter 4313-E/4313-A/4313-B

The percentage of RPS Procurement currently under contract for 2020 for each of the three major utilities in California are: (i) PG&E at 31.3%; (ii) SCE at 23.5%; and (iii) SDG&E at 38.8%.[42] These values are projected to increase substantially to meet RPS interim goals.

5.5 Strengths and weaknesses

Strengths of the centralized procurement programs are generally considered to be:

- having the procurement processes managed by the individual IOUs gives the utilities more independence and greater flexibility to reach their RPS targets, and reduces the administrative burden on the CPUC;
- implementing a variety of different programs for the IOUs to procure from (including those that offer expedited procurement) proves useful for long and short-term planning;
- using bid deposits, development deposits and performance deposits has been effective at preventing frivolous bids and ensuring a robust procurement system; and,
- by implementing regular revisions of programs such as the RAM, and involving customers in the procurement process (i.e. through the Division of Ratepayer Advocates ("DRA")), procurement processes can constantly evolve according to stakeholder feedback and changing market conditions.

Critiques of the program include:

- the utility scale RFO program is considered to be a very drawn out process that lasts more than a year, owing partly to the multiple stages of evaluation and approval offers have to go through and multiple parties that are involved in the process;
- the ability of the IOUs to renegotiate bilaterally at any phase in the process does not comply with best practices. While active third party oversight of the procurement process,

[42] California Public Utilities Commission. *RPS Procurement Programs.* Accessed February 29, 2016. <http://www.cpuc.ca.gov/RPS_Procurement_Programs/>

including bid evaluation, probably ensures that California's ratepayer interests are protected, it does not signal to bidders that they will all be treated equally;

- the non-price criteria, such as "compliance with state RPS goals" and "ensuring supplier diversity," are only vaguely described and how those criteria are factored into the bid evaluation process is not articulated;

- information on resulting winning (or losing) bids for either the RFO or RAM procurement processes is not provided. This does not help inform the market of what is or is not competitive and does not provide additional transparency to demonstrate the competitiveness of the procurement process.

5.6 Implications for Alberta

- California does not technically run a centralized procurement process in that procurement for the state is not run by one entity. However, California is a large market and is sufficiently large that its renewables procurement can be divided among its utilities. In the interest of ensuring a competitive outcome, the regulator plays an active role in ensuring that the process is designed to be competitive and fair and that the outcomes are competitive. The added benefit of having the procurement process be designed by the regulator is that the processes and requirements for all three utilities are very similar, facilitating developers to participate in more than one utility's process.

- California uses two different approaches for competitively acquiring renewable projects. Its RAM approach was developed so that they could have a shorter timeframe procurement process (six months as compared to 18 months for the RFO) for smaller projects. This makes sense in the California context where they are developing large quantities of renewables and have had significant experience running centralized procurement processes. This is probably not advisable for a jurisdiction that is just starting to run competitive procurement processes where it would make sense to start with a single procurement structure in the early years at a minimum.

- While California does use a Market Referent Price, which provides it with indicative pricing estimations, it is not a firm price cap which opens California up to potentially paying more than expected for its renewables.

- Because California's utilities manage the procurement process, California has a very robust oversight process in place which includes multiple levels of oversight and approval. This may be excessive in a jurisdiction where an independent objective entity manages the procurement process.

- California, like Ontario, is using a continuous improvement process with its procurement efforts, taking feedback after every process and tweaking the process to improve the procurement each time. This has the benefit of creating a superior procurement process but has the negative side effect of requiring bidders to learn about any changes to the process each time.

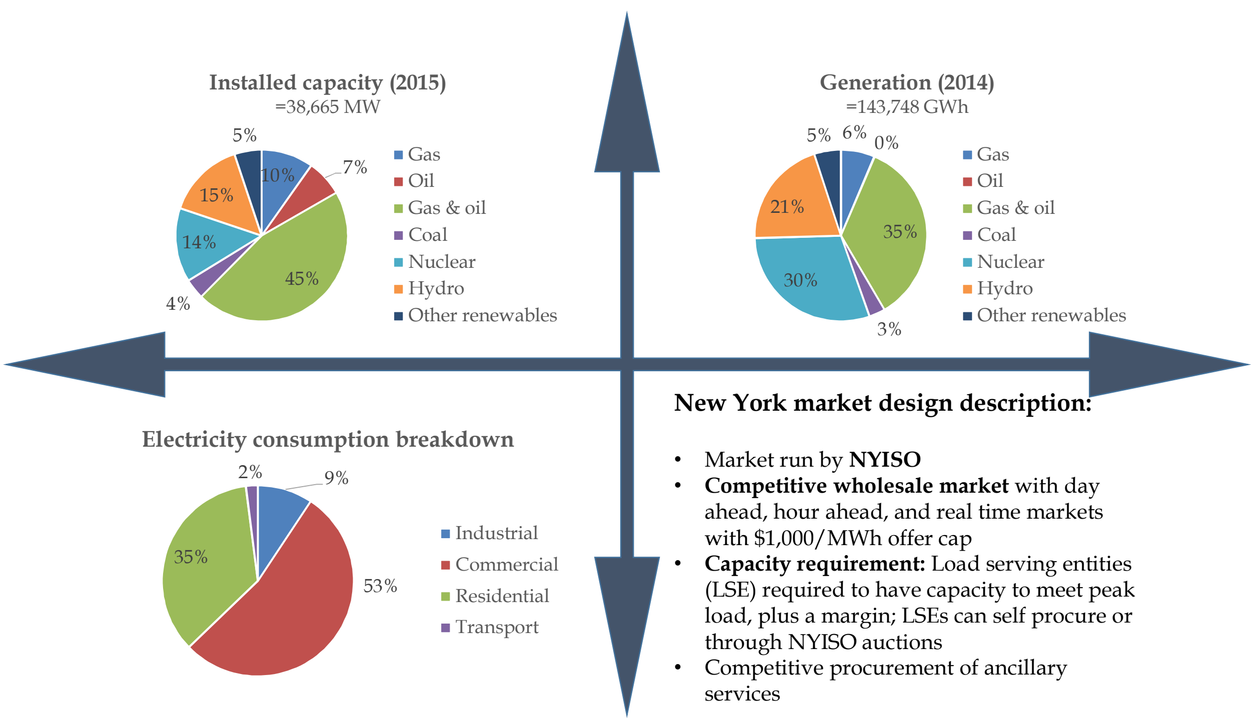
6 New York Main Tier Solicitations

6.1 Context

6.1.1 New York market characteristics

New York State has an installed capacity of almost 39,000 MW, and generates the bulk of its electricity using gas, nuclear, and hydroelectric resources. Coal represents a very small percentage of both installed capacity (4%) and generation (3%) and New York's Governor Cuomo announced earlier this year plans to shut down or repower all remaining coal-fired plants by 2020. New York's power market is a single state system, run by the New York Independent System Operator ("NYISO"). It is a competitive wholesale market, with day ahead, hour ahead, and real time markets. Offer bids into those markets are capped at US$1,000/MWh. To ensure reliability, all load serving entities in New York are required to procure capacity to cover their peak load obligations, plus a margin. That requirement can be self-supplied, procured on bilateral markets or through the NYISO's regular capacity auctions. New York's electricity consumption is dominated by commercial load (53%), while industrial load represents only 9%.

Figure 22. Overview of New York electric power market characteristics



Source: NYISO, EIA, FERC

6.1.2 New York renewable energy targets

In September 2004 following extensive stakeholder input, the New York Public Service Commission ("NYPSC") issued an order ("2004 Order") adopting a Renewable Portfolio Standard ("RPS") with an objective of increasing the percentage of renewable energy used by New York from 19.3% to 25% by the end of 2013.[43] The NYPSC increased that goal in a January 2010 Order, increasing the target to 30% by 2015.[44] The NYPSC specified in the 2004 Order that the majority of the renewables should be achieved through a central procurement process, with the New York State Energy Research and Development Authority ("NYSERDA") serving as the central procurement administrator. In that same order, the NYPSC authorized the state's investor owned utilities to collect funds from ratepayers through a non-bypassable volumetric surcharge on delivery charges to fund the program.

NYSERDA is responsible for both the Main Tier procurement, which targets utility-scale projects, as well as the program to support the acquisition of customer sited projects (Customer Sited Tier). In this case study, we focus on the Main Tier procurement which is run as a competitive solicitation as compared to the Customer Sited Tier program which is structured as a first-come/first served enrollment program. New York also has a separate incentive program for solar projects, NY-SUN, which uses a declining tariff by category.

Overview of NY's Main Tier:

- NYPSC sets key elements to procurement targets and approach
- NYSERDA serves as procurement manager
- Procure environmental attributes for terms of 10-20 years
- All eligible renewables compete against one another to achieve lowest possible price
- Economic development component included in bid evaluation
- Has not achieved targets due to insufficient budget
- Entire approach to renewable development in process of being re-evaluated and restructured

6.2 Key process design attributes

6.2.1 Establishing resources needs

The NYPSC has set out most of the details related to the requirements of renewable procurement in its various orders in the RPS docket and NYSERDA implements them in its role as central procurement administrator. The NYPSC establishes the specific target of MWhs that need to be procured (by calculating total anticipated retail load by year, and subtracting from that the baseline of existing generation, anticipated purchases from government agencies, the Long Island Power Authority, and voluntary "green electricity" purchases) to establish annual targets through 2015. The NYPSC also set the budget for the RPS, allowing for US$741 million to be collected from ratepayers over the 2005-2013 timeframe in the 2004 Order. That schedule, which

---

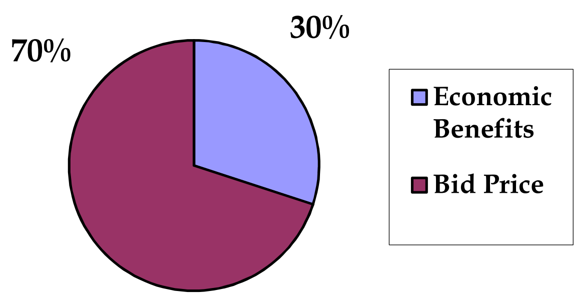
[43] State of New York Public Service Commission, "Order Regarding Retail Renewable Portfolio Standard," September 24, 2004, hereafter referred to as the "2004 Order."

[44] State of New York Public Service Commission, "Order Resolving Main Tier Issues," April 2, 2010.

is laid out in the 2004 Order, specifies collections by year by utility, essentially providing NYSERDA with its budget for running centralized solicitations.

The NYPSC specifies eligible resources and technologies, which has expanded slightly over time. Eligible resources include biogas, biomass, liquid biofuel, fuel cells, hydro, solar, tidal power, and wind. Resources must have been installed, or expanded after January 1, 2003 to be eligible to participate in Main Tier solicitations.[45] The electricity associated with the renewable attributes must be delivered into a market administered by the New York Independent System Operator ("NYISO") and delivered through a wholesale meter such that it can be measured, tracked, and verified by the NYISO.

Figure 23. Breakdown of NYSERDA Main Tier Bid assessments



Finally, the NYPSC also set out economic development criteria for projects participating in the Main Tier solicitations, which are spelled out in the RFP documents. Those criteria, which are weighted 30% out of the total economic assessment, focus on identifying the anticipated incremental economic benefits that will accrue to New York State as a result of the development, construction, and operation of the renewable energy facility. Those benefits include long term jobs, payments to New York State or New York municipalities (taxes, etc.), payments for fuels and resources access (i.e., land leases, biomass purchase, etc.), in-state purchase of goods, and short term employment (i.e., construction).

6.2.2 Managing procurement process

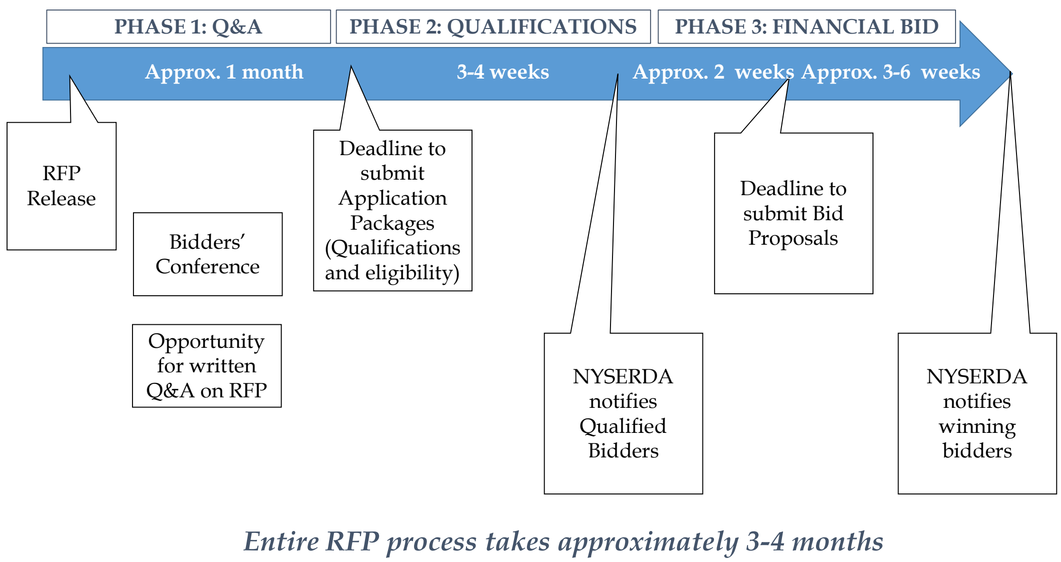
NYSERDA serves as New York's central procurement administrator. NYSERDA was selected to manage the RPS procurement process because the NYPSC saw efficiencies in scale by centralizing all procurement across the state (as opposed to having utilities manage it individually, for

[45] Note that in the 2004 Order, the NYPSC did allow for renewable resources that were in existence prior to 2003 that have a demonstrated financial hardship to apply for RPS funding as a Maintenance Resource, which is granted by the NYPSC after reviewing full financial documentation. These assets, which represent a small fraction of overall Main Tier funding, do not however participate in the centralized procurement process so we do not discuss them in the rest of this document.

example) and because NYSERDA had procurement experience from its work securing energy efficiency projects using system benefit funds.[46]

NYSERDA's competitive solicitations are for the environmental attributes only, not for the aggregated product of electricity supply and the environmental attributes. In exchange for receiving what is called a "production incentive," the winning renewable generators transfer to NYSERDA all rights and/or claims to the environmental attributes associated with each MWh of renewable electricity generators and guarantees delivery of the associated electricity to New York State ratepayers. The intent of this structure was "to minimize interference with the State's competitive wholesale power markets."[47]

Figure 24. Overview to NYSERDA Main Tier RFP process



There is no set timing schedule to NYSERDA's Main Tier solicitations. Rather, these are scheduled when sufficient funds have accumulated from ratepayer collections and when market conditions appear favorable for lower prices. For example, the first solicitation was not supposed to occur until 2006 but because of concern about the expiration of the federal tax credits, NYSERDA held its first solicitation in January 2005.[48]

NYSERDA's solicitations are usually managed within a three to four month time horizon and have three distinct phases as shown in the graphic above. The first phase is the Q&A phase. Once the RFP is released, there is a period during which potential bidders can ask questions, both at a

[46] 2004 Order, p. 54.

[47] NYSERDA. *History of the NYS Renewable Portfolio Standard*. Accessed March 29, 2016. <http://nyserda.ny.gov/All-Programs/Programs/Main-Tier/History>

[48] New York State Public Service Commission. "Order Approving Implementation Plan, Adopting Clarifications, and Modifying Environmental Disclosure Program." April 14, 2005, p. 5.

bidders' conference and through a written process. The second phase is the qualification phase. Bidders usually have about a month from the RFP release date to submit their Application Packages. Bidders must be deemed qualified by NYSERDA after reviewing their Application Packages in order to pass on to the next phase. Factors that NYSERDA assesses in the qualification phase include: eligibility and provisional or actual operational certification, depending on the project's status. The third and final phase is the bidding phase. Bidders that pass the qualification phase are invited to submit bid proposals which contain their price bid as well as information on their economic development value. NYSERDA then evaluates those bids (as is discussed in detail in the next subsection) and announces winning bidders within a month or so.

6.2.3 Ensuring competitive outcomes

Ensuring a price competitive outcome and minimizing impact on the wholesale market was of key concern to the NYPSC as it set up the Main Tier procurement process. The 2004 Order specified that NYSERDA will "award financial incentives that are the minimum necessary to stimulate development of generational facilities."[49] The NYPSC purposefully designed the Main Tier solicitations to have many types of technologies compete against one another on the basis of price (and incremental economic development benefits). As a result, this process gives an inherent benefit to technologies that are lower cost than others. Small scale hydro and biogas resources are viewed as having a particular cost advantage in New York.[50]

Bidders are given specific directions, including:

- bids are considered a binding offer and must remain valid for 60 days after the submission deadline;
- bidders may submit bids for a minimum of one year up to a maximum allowed for their specific technology;[51]
- each proposal must refer to a specific facility;
- the bid quantity percentage must be at least 30% and cannot exceed 95%;
- bidders must also provide a detailed description and quantification of the incremental benefits that are created by their project in New York State, and propose a verification plan to assess those benefits; and

[49] 2004 Order, p. 4

[50] New York Public Service Commission, "Order Resolving Main Tier Issues," April 2, 2010, p. 6.

[51] The age ranges based on assumed useful life from 10 years for tidal power to 15 years for landfill gas to 20 years for most other technologies; hydroelectric facilities have a potential useful life of 50 years but 20 years is the maximum term under the RFP rules.

- proposals may not exceed 20 pages in length and NYSERDA specifies paper size and font minimums.

Bid evaluation

Bid proposals are evaluated by a "Technical Evaluation Panel," which consists of NYSERDA staff, Department of Public Service staff, and independent outside reviewers. NYSERDA is explicit about how it evaluates the bid proposals. 70% is allocated to the bid price evaluation, while 30% is allocated to expected economic benefits to New York. Both components are evaluated separately.

Figure 25. Overview to NYSERDA Main Tier bid evaluation approach

Phase 1: simultaneous review of economic benefits and bid price

Economic Benefit Review
- Long term jobs
- Payments to New York State or New York municipalities (taxes, etc.)
- Payments for fuels and resources access (i.e., land leases, biomass purchase, etc.)
- In-state purchase of goods
- Short term employment (i.e., construction jobs)

Up to 30 points allocated

Bid Price Evaluation
- All technologies compared against one another
- Bid prices recalculated into "Bid Price Evaluation Metric" to enable apples to apples comparison of different contract tenors
- NYSERDA sets maximum acceptable Bid Price Evaluation Metric; bids above that are deemed ineligible
- Eligible bids ranked in order of Bid Price Evaluation Metric and allocated points based on that order

Up to 70 points allocated

Phase 2: ranking and selection
- Total points aggregated from economics benefits review and bid price evaluation
- Eligible projects ranked in order of score – highest to lowest
- Projects then selected from top ranking projects based on procurement target and available funds

For evaluation purposes, bid prices are converted to a "Bid Price Evaluation Metric" to enable the equitable comparison of bids of different terms.[52] NYSERDA separately develops its own maximum acceptable Bid Price Evaluation Metric (essentially a cap on what price it will accept). NYSERDA will not award a contract to any facility whose Bid Price Evaluation Metric is above their maximum level. Bids are sorted in ascending order based on their Bid Price Evaluation Metric. The lowest bid receives the maximum points available (70) and the other bids are awarded points based on where they fall in the range of from lowest to highest eligible bids, though NYSERDA does not specify how exactly it allocates those points.

---

[52] To do this, NYSEDA calculates the Net Present Value ("NPV") of expected contract payments by multiplying the bid price by the annual bid quantity and dividing that by a pre-specified discount rate, which is adjusted based on the term of the contract. That NPV is then divided by the sum of the annual bid quantity multiplied by the contract term to derive the "Bid Price Evaluation Metric."

The points for the economic benefits are allocated by reviewing each bid proposal in detail. Only economic benefits meeting the RFP's eligibility criteria and falling into the specific categories outlined by the RFP will be considered. Each proposal is granted up to 30 points for economic benefits.

All eligible projects (projects with bids that have a price above NYSERDA's Bid Price Evaluation Metric will be considered ineligible) will then have their scores aggregated. Selection is based on this final ranking subject to NYSERDA's procurement target and available funds, both of which are stated in the RFP.

NYSERDA reserves the right to solicit revised bid prices and/or to make counteroffers as it deems appropriate.

Other mechanisms

There are several mechanisms in place to ensure that the bidders are committed to their project and the commitments made as part of the RFP process. First, bidders are required to submit a bid deposit when they submit their Application Package. That deposit varies by the size of the project, with US$5,000 required for projects that are 5 MW or smaller and US$100,000 required for projects that are 50 MW or bigger. The deposits are refunded to bidders who do not pass the qualification process or whose financial bids are not ultimately selected.

Next, winning bidders must submit a contract security within 10 business days of their selection. That security is set at US$6/MWh times the annual bid quantity. An additional US$3/MWh is required the following year (the year before the plants' assumed commercial operation date). The winning bidder forfeits a pro rata share of that security if the installed capacity is less than the bid capacity. NYSERDA's contractual terms also protect it from under performance (when the facility generates less than bid). NYSERDA is able to adjust the bid quantity to a lower amount or put the contract into default if it generates less than 65% of the bid quantity. Similarly, if bidders are not able to demonstrate that the promised economic benefits articulated in the bid proposal are at least 85% of what was in the bid proposal, NYSERDA may reduce the bid price payable by a pro rata share (comparing actual economic benefits to economic benefits promised in the bid proposal).

Finally, NYSERDA is required to publish an annual performance report on its management of the RPS procurement (both Main Tier and Customer Sited). In addition, there is third party evaluation of the program every few years (funding for which comes from program funds).

6.3 Transmission

Transmission is not addressed as part of New York's Main Tier solicitation process. For facilities to be eligible to participate in the Main Tier RFP, they have to demonstrate that they can deliver electricity into the NYISO system.

In the 2009 evaluation of the RPS, NYSERDA did consider whether they should consider facility location as part of the procurement process, so that it could encourage projects to be sited in more optimal locations on the transmission system, reduce grid congestion, and/or potentially offset polluting facilities. However, NYSERDA ultimately determined that "a locational criterion may simply add complication and potential ambiguity to the bid award process."[53]

6.4 Outcomes

After ten solicitations, New York's Main Tier has 70 active projects under contract totaling 2,512 MW of new renewable generation capacity. 90% of that capacity is wind, though a wide variety of project technologies have been funded as is illustrated in the table below. Prices for the renewables attributes being purchased by NYSERDA have varied substantially over the last 10 years, from a low of US$14/MWh in 2007 to a high of almost US$35/MWh in 2013. However, these are not all directly comparable, given that the terms of the contract increased from 10 year to 20 years starting in the 9th solicitation.

Figure 26. List of completed New York Main Tier Solicitations

Solicitations	Date	MW Procured	Total Funding Commitment (US$ millions)	Weighted average price (US$/REC)	Technologies
10th	May-15	116	$ 175	$ 24.57	wind; AD; fuel cell; hydro
9th	Aug-14	164	$ 206	$ 22.96	windo; hydro
8th	Jan-13	50	$ 66	$ 34.95	wind; hydro; AD; fuel cells
7th	Dec-11	88	$ 132	$ 28.70	biomass; wind; hydro;LFG
6th	Jun-11	315	$ 191	$ 22.01	wind; hydro; LFG;AD
5th	Mar-10	318	$ 204	$ 21.17	wind; hydro; biofuel; LFG; biomass
4th	Oct-09	142	$ 96	$ 19.76	wind; hydro; biomass
3rd	Nov-07	150	$ 119	$ 14.75	wind; biomass; hydro
2nd	Dec-06	880	$ 264	$ 15.52	hydro; wind; biomass
1st	Jan-05	254	$ 174	$ 22.90	wind; hydro

Note: NYSERDA is only procuring the environmental attributes, not commodity supply, in these solicitations; AD= Anaerobic Digester; LFG = Landfill Gas

Source: http://www.nyserda.ny.gov/All-Programs/Programs/Main-Tier/Main-Tier-Solicitations

While NYSERDA has procured a significant amount of renewable generation capacity over the last 10 years, as demonstrated in the chart above, it has not achieved its RPS goals. In its March

[53] NYSERDA. "New York Renewable Portfolio Standard Program Evaluation Report - 2009 Review." March 2009. P. 47.

2015 Annual Performance Report (the latest available), NYSERDA stated that it had achieved 53% of its targeted 9,519,765 MWh as of December 31, 2014.[54] The main reason that NYSERDA has not achieved its targets is because the funding allocation by the NYPSC, made in 2004, underestimated how much it would cost to procure these resources and has never been updated. This was clearly acknowledged in the 2009 review and indeed the entire RPS program is under revision, as will be discussed more in the next subsection.

6.5 Strengths and weaknesses

There have been several evaluations of the NYSERDA Main Tier procurement approach, which have all fed into the current process to completely revamp New York's RPS. Part of this is to address New York's recently updated RPS target (50% by 2030)[55] as well as to better coordinate with its ongoing Reforming the Energy Vision ("REV") initiative, which aims to better integrate distributed resources including demand side resources into the supply mix. However, these changes are also in response to concerns about weaknesses in the Main Tier procurement process.

Strengths of the Main Tier program have generally been considered to be:

- central procurement approach, which has generally been considered successful and cost effective;
- use of a bid price ceiling to set a maximum level for projects, which has enabled NYSERDA to not feel pressured into high priced contracts;
- policymakers view the use of economic development criteria and requirement for in-state purchasing as effective; and
- use of a contract security has been effective at preventing frivolous bids.

Concerns that are to be addressed in the revised approach include:[56]

- policymakers in New York view REC-only contracts as no longer sufficient and responsible for overall increased costs. Because REC contracts with NYSERDA are the only source of revenue certainty for renewable developers, this increases their cost of capital and limits their access to innovative financing structures;

---

[54] NYSERDA. "New York State Renewable Portfolio Standard: Annual Performance Report through December 31, 2014." March 2015. P. 7.

[55] Note that this new proposed approach, which is currently being debated through a public stakeholder process, would include several major changes to New York's RPS including the establishment of several "clean energy tiers" including new renewables, existing renewables, and zero carbon resources (nuclear), interim triennial targets by tier, use of a REC trading platform for compliance, use of an alternative compliance payment for each tier to cap prices and provide an alternative means of compliance, as well as continued long term procurements by both NYSERDA and the state's utilities for a bundled commodity and REC product to support project financing and to provide both generators and customers with greater price stability.

[56] NYSERDA. "Large Scale Energy Development in New York: Options and Assessment." June 2015. P. 39-40.

- the current RPS structure does not ensure that projects are sited to optimize system benefits, which is becoming increasingly important with NY policymakers, as seen as part of its Reforming the Energy Vision initiative; and

- the currently approach does not engage end customers, which is another key element of the REV initiative.

Other critiques of the program include:

- insufficient funding for achieving target: The NYPSC set anticipated costs for achieving the RPS in 2004. Those estimates were too low but the collection from utilities for the RPS was never updated so there was never any way for the Main Tier solicitations to achieve their objectives;

- too much uncertainty for developers: Solicitations were not scheduled in advance and were not on a regular schedule so developers could not count on them; and

- current rules do not enable NYSERDA to re-allocate unused funds (from projects that have not managed to develop their project, for example) back into their budget, further exacerbating the budget issues.

It is important to note that New York's original RPS and centralized procurement approach was developed more than 10 years ago. The market for developing and financing renewables, as well as the overall policy context in New York, has changed considerably since then. Expectations that the NYPSC had about the voluntary market enabling renewable development and that the renewable industry would become self-sustaining within this timeframe have not materialized, while New York's policy goals vis-à-vis renewables have become even more ambitious. Thus, the large-scale changes currently being considered for New York's RPS and centralized procurement have to be viewed within that context. And, indeed, the fact that centralized procurement is likely to remain a key plank in New York's approach to developing and supporting new projects is a testament to the general success that NYSERDA has had with its Main Tier solicitations.

6.6 Implications for Alberta

There are several key takeaways from New York's experience that might prove useful to Alberta policymakers as they contemplate the best approach for supporting increased renewable development.

- Setting an overall renewables goal is only a first step. It is helpful for policymakers and developers alike to break that large goal into interim milestones. In addition, it is useful to schedule assessments of the program every three to five years so that improvements, including up to date funding allocations, can be incorporated on a timely basis.

- Price caps can help contain costs. Using a not to exceed price cap that is based on up to date market data is a good way to ensure the cost-effectiveness of the program.

- A technology neutral procurement will ensure that the renewables developed are the lowest cost.

- There are limitations to a REC only procurement process. The incremental funding that developers obtain from a stream of REC contracts may not provide sufficient revenue certainty to facilitate financing and operating the project, increasing their cost of capital and the overall cost of the project.

- Non-price criteria can be utilized for incorporating other public policy goals, though at the cost of increasing the complexity and subjectivity of the bid evaluation. It is possible to incorporate non-price criteria into the bid evaluation process, but it is important to be explicit with bidders about what information is needed, how it will be evaluated, and how it will feed into the bid selection process.

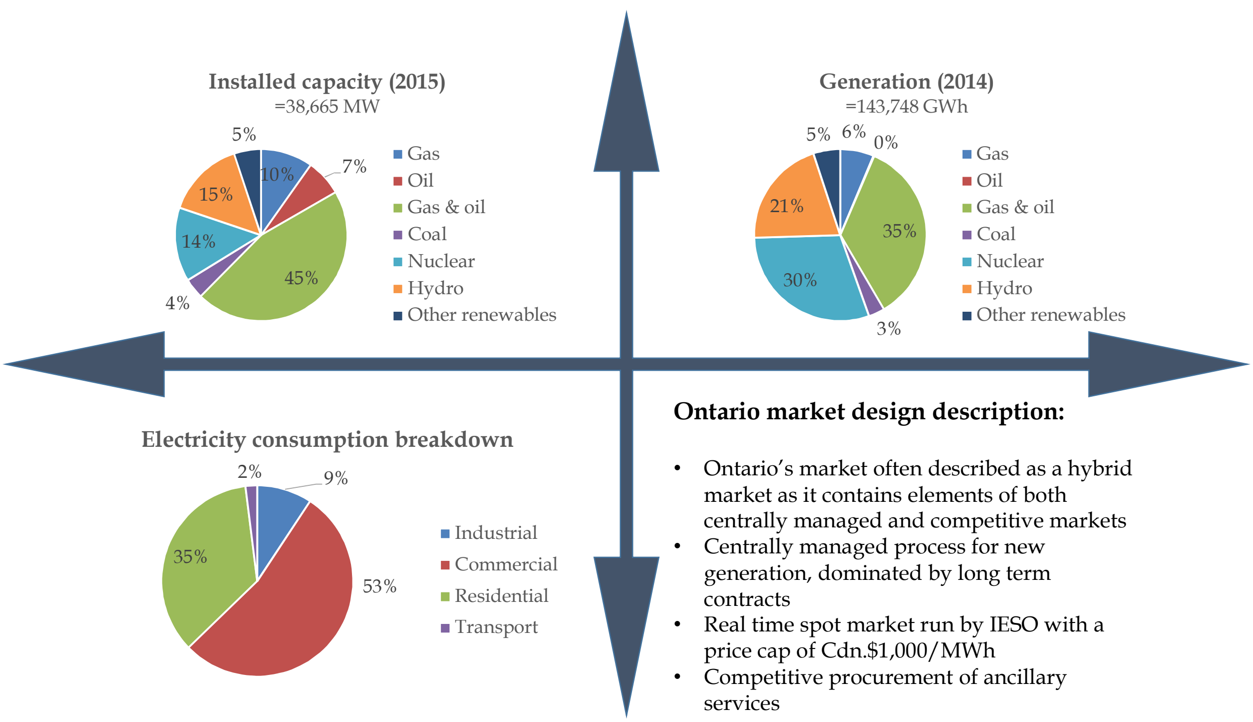
7 Ontario large renewable procurement

7.1 Context

7.1.1 Market characteristics

Ontario has an installed capacity of almost 35,221 MW and generates the bulk of its electricity using nuclear and hydro. Coal was entirely (and purposefully) phased out by 2014 and transmission connected solar capacity is now at 140 MW. Currently, power generators bid into and receive dispatch instructions from a wholesale market administered by the Independent Electricity System Operator ("IESO") with retail choice at the consumer level. However, Ontario's electricity market largely consists of long term contracts with a principal buyer, the former Ontario Power Authority ("OPA"), now merged with the IESO, which is heavily influenced by the provincial government.

Figure 27. Overview of Ontario electric power market characteristics



Source: IESO power data, Ontario Electricity Demand 2012 Annual Long Term Outlook OPA

7.1.2 Renewables targets

In December 2013 the Ministry of Energy released the Ontario Long-Term Energy Plan ("LTEP") which acts as the policy roadmap for Ontario. Renewable targets are set by the LTEP and directed by the Minister to the IESO. The LTEP states that by 2025, 20,000 MW of renewables will be online and that Ontario will phase in 10,700 MW of wind, solar, and bioenergy by 2021.[57]

The LTEP also committed to reviewing these renewable targets annually as part of the Ontario Energy Report and to developing a new competitive procurement for all future renewable projects greater than 500 kW. The development of this competitive procurement was assigned to the former Ontario Power Authority ("OPA"), now the Independent Electricity System Operator ("IESO").

Under the Ministry of Energy's directive, the IESO is responsible for designing and administering the large renewable procurement to target utility-scale projects. The LTEP specifically noted the maximum procurement targets per fuel type that the program should procure in the first competitive procurement:

- 300 MW of On-Shore Wind;
- 140 MW of Solar;
- 50 MW of Bioenergy; and
- 75 MW of Waterpower.[58]

In this case study, we focus on the Large Renewable Procurement ("LRP") I which is the current competitive solicitation process for large renewables in Ontario.

7.2 Key process design attributes

7.2.1 Establishing resources needs

The IESO was directed by the Minister of Energy in June 2013 to discontinue the Large Feed in Tariff ("FIT") program and replace it with a competitive procurement process for large renewable energy projects (capacity over 500 kW). The Ministry's decision to end the Large FIT and procure large renewables competitively using flexible targets came as a result of critics who voiced

[57] Ontario Ministry of Energy. *Ontario's Long-term Energy Plan*. 2013. <http://www.energy.gov.on.ca/en/files/2014/10/LTEP_2013_English_WEB.pdf>

[58] Ibid.

concern over "lowered demand growth and rising electricity price pressures caused by the FIT subsidies."[59]

The Minister encouraged the IESO to ensure that they developed a competitive process that engaged municipalities to help inform siting requirements and considered local needs as well as input from stakeholders and Aboriginal communities.[60] The IESO was required to provide interim feedback on the development of this process to the Minister and began holding stakeholder engagements in the summer of 2013 to engage key stakeholders in the development of the procurement process, its requirements, and its evaluation. In August 2013, feedback and interim recommendations from the stakeholder engagement process were compiled in a comprehensive report for the Minister of Energy. The Ministry used results of the IESO stakeholdering as input for the 2013 Long Term Energy Plan ("LTEP"). Quantities of each type of fuel type to be procured were prescribed by the LTEP and in subsequent procurements would be a result of a combination of Ministry directive and public stakeholder consultation by the IESO.

In addition to specific procurement targets, the LTEP also signaled that the LRP program adhere to the following principles:

- follow a provincial and/or regional electricity system need;
- consider municipal electricity generation preferences;
- engage early and regularly with local and Aboriginal communities;
- occur in multiple successive rounds, providing opportunity for a diverse set of participants;
- identify clear procurement needs, goals, and expectations; and
- encourage innovative technologies and approaches, including consideration of proposals that integrate energy storage with renewable energy generation.[61]

The IESO and the Ministry of Energy engaged with the public, municipalities, Aboriginal communities, and other groups on the design of the LRP program during the period of July 2013 to February 2014. At the conclusion of this stakeholder engagement, the IESO issued a final recommendations report to the Ministry for approval. The report was approved by the Minister with minor additional direction, at which point the IESO was able to publish materials required for applicants to begin the LRP competitive procurement. On March 10, 2015, the IESO issued the first LRP RFP and winning bids were announced in March 2016, as is detailed in Section 7.4. The

[59] Solar Canada. *From FIT to LRP: Utility-Scale Solar Power in Ontario*. March 2015.

[60] Ontario Minister of Energy Directive to the Ontario Power Authority. *Re: Renewable Energy Program*. June 2013. <http://www.powerauthority.on.ca/sites/default/files/MC-2013-1450-DirectionRenewableEnergyProgram.pdf>

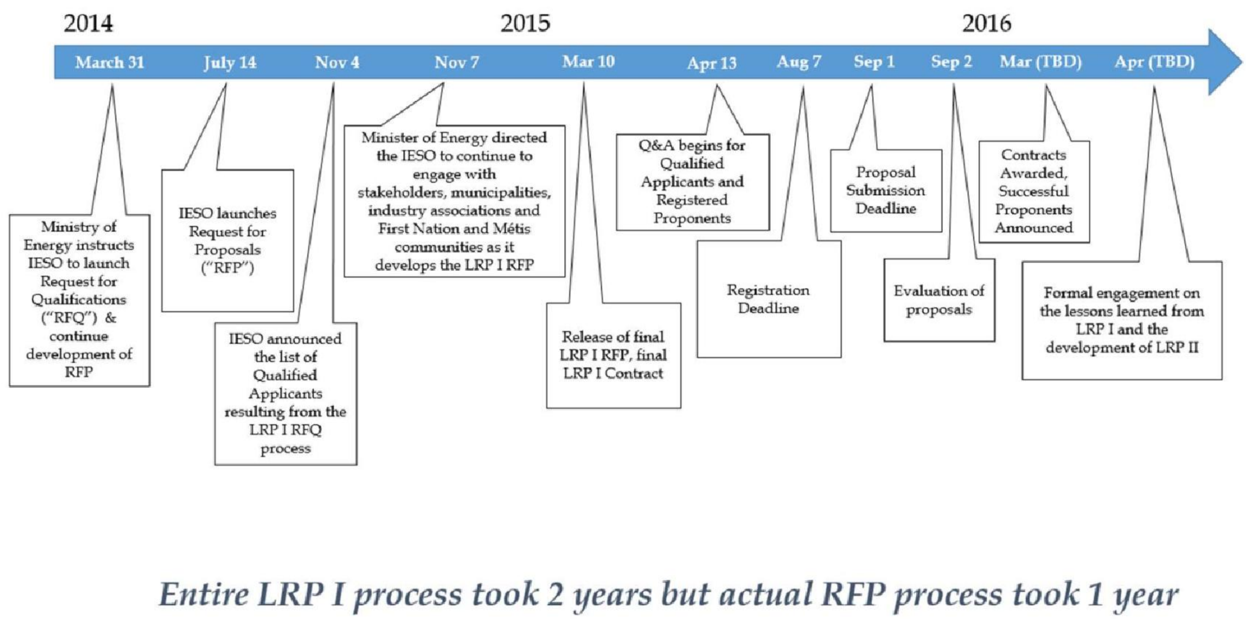
[61] Ibid.

LRP RFP is limited to new projects and projects have to come on-line within a specified time, which varies by technology – three years for solar and biomass, for example, four years for onshore wind, and eight years for hydro.

7.2.2 Managing procurement process

The LRP process is run by the IESO and seeks to procure renewable electricity from large scale projects.[62] It will result in 20 year contracts for the purchase of power.

Figure 28 Overview of the LRP process



The process to participate in the LRP process included an initial Request for Qualifications ("RFQ") to qualify applicants, followed by a Request for Proposals ("RFP") to evaluate projects by those applicants that were qualified. The RFQ pre-screened developers by analyzing their experience, technical capability and their ability to finance large renewable projects. The requirements of the RFQ *"have been formulated to identify those interested parties with the technical experience, financial resources and willingness to deliver one or more Large Renewable Project(s) in accordance with the OPA's [presently IESO's] requirements."*[63] The two stages of the RFQ evaluation were Stage 1: Completeness Requirements (the IESO checked to make sure all necessary application forms were included and substantially completed – these forms included a

[62] Ontario does not have an actual Renewable Energy Certificate ("REC") market – renewables are procured to be a part of the overall supply mix. However, because the IESO is taking ownership of the environmental attributes, this is essentially a bundled product for the sake of our cross-case study comparisons.

[63] Ontario Power Authority. *Request for Qualifications for the Procurement of Up to 565 MW of New Large Renewable Energy Projects.* July 14, 2014.

demonstration of Tangible Net Worth, and payment of a qualification application submission fee which was upwards of Cdn.$30,000 depending on the estimated size of the project that the applicant would eventually submit).[64] Stage 2 of the RFQ process entailed an assessment of "Mandatory Requirements," including a demonstration of an applicant company's development experience with similar facilities or infrastructure projects and demonstrations of the applicant company's representative's development experience as well. This stage also required the applicant company to demonstrate tangible net worth through disclosure and proof of commitment of an equity provider, and financial statements. Only those applicants successful in the RFQ stage were able to submit RFP proposals.

Following the RFQ process the IESO posted a list of qualified applicants and their proposed projects and project MW capacity. Any space that is left in each of the blocks may be reallocated to the procurement targets of the next LRP.

7.2.3 Ensuring competitive outcomes

The RFP evaluation Stages 1- 4 ensured competition based on both qualitative project/proposal attributes and then on price. Proposals were required to provide proof of due diligence in the areas of community and municipal engagement and aboriginal participation before they were judged on price. Failure to demonstrate requirements of Stage 1 or Stage 2 would result in failure of the proposal – before the price submission was opened. The third stage of the evaluation was optional and, if successful, those projects that applied would receive points that would later be applied as an adjustment to their price bid, making it more competitive.

The four stages of the LRP competitive procurement process are:

Stage 1: Completeness Requirements (Mandatory, Pass or Fail)

- Ensure all necessary forms are present
- Includes: security payments, declarations and applicable evidence as required in the RFP

Stage 2: Mandatory Requirements (Mandatory, Pass or Fail)

- Ensure that the developer has completed all of the requirements in the LRP program prior to submitting their application to the IESO
- Includes: a project community engagement plan, proof of public community meetings, proof of meeting(s) with the project municipality, access rights declaration, various site, land, and environmental considerations including a site report prepared and approved by an independent engineer and connection parameters

[64] Ibid.

Stage 3: Rated Criteria (Optional, 0 – 100 point score awarded)

- Projects were able to apply for rated criteria points which could make their proposals more competitive in the evaluation and selection process. These points were awarded to projects who applied for them if they demonstrated requirements satisfactorily

- **Community Engagement (up to 80 points could be awarded)**

    - Project is able to reach a support resolution with the municipality/first nation community
    - Project is able to demonstrate a municipal agreement
    - Project obtained a certain amount of abutting landowner and/or Crown Land leaseholder support

- **Aboriginal Participation (20 points)**

    - Project is able to demonstrate one or more Aboriginal Communities holds a direct/indirect economic interest (must be at least 10%) in the project

Stage 4: Evaluation and selection (Identify selected proponents)

- In this section an independent team reviews the Evaluated Proposal Price (described below) and the availability of capacity at the project's proposed connection point
- Projects that scored Rated Criteria points will have a reduction to their proposed project price
    - The adjusted price becomes the "Evaluated Proposal Price"
- To ensure a competitive price for Ontario's ratepayers, the LRP establishes an administrative maximum price for each fuel type. *"The Maximum Weighted Prices were established using IESO's internal data, industry feedback, and international and North American pricing trends for LRP-sized projects."*[65]
- Once Evaluated Proposal Prices are calculated they are arranged from lowest to highest and tested against available connection capacity – ensuring that where capacity availability can accommodate, lowest priced projects are taken first.

Evaluated Proposal Price

The IESO uses a detailed methodology to evaluate proposal prices. Many of the underlying assumptions used in those calculations are disclosed in the RFP, as discussed below.

With each proposal the applicant must submit both an On-Peak and Off-Peak price in units of (Cdn.$/MWh) that the IESO uses to derive a "Weighted Price." The Weighted Price and Evaluated Proposal Price along with assumptions published by the IESO are detailed below.

---

[65] IESO. *LRP I RFP Backgrounder – Evaluated Proposal Price.* March 10, 2015.

Weighted Price = **(**On Peak Price X On Peak Average Capacity Factor ("ACF") X On Peak Time + Off Peak Price X Off Peak ACF X Off Peak Time) ÷ Weighted ACF[66]

Where:

Weighted ACF = On Peak ACF X On Peak Time + Off Peak ACF X Off Peak Time[67]

The energy production assumptions used by the IESO in the above two equations were prescribed and published with the RFP as shown below:

Figure 29. Energy production assumptions in LRP I RFP

Renewable Fuel	On-Peak ACF	Off-Peak ACF	On-Peak Time	Off-Peak Time	Weighted ACF
Bioenergy (Renewable Biomass, Biogas, and Landfill Gas)	0.850	0.850	0.43	0.57	0.85
Solar (Rooftop Solar and Non-Rooftop Solar)	0.235	0.080			0.15
Waterpower	0.550	0.550			0.55
On-Shore Wind	0.280	0.305			0.29

The Weighted Price cannot be greater than the maximums for each fuel type which was administratively set and published in the RFP as shown in the graphic below.

[66] Ibid.

[67] Ibid.

Figure 30. Not to exceed price limits in LRP I

Renewable Fuel	Maximum Weighted Price
Biogas	Cdn.$164
Renewable Biomass	Cdn.$156
Landfill Gas	Cdn.$111
Non-Rooftop Solar	Cdn.$275
Rooftop Solar	Cdn.$316
Waterpower	Cdn.$177
On-Shore Wind	Cdn.$115

(Source: *LRP I RFP Backgrounder – Evaluated Proposal Price. March 10, 2015.)*

From here the IESO determines Evaluated Proposal Price which is calculated as:

Evaluated Proposal Price = (On-Peak Price x On-Peak Factor + Off-Peak Price x Off-Peak Factor) x Dollar-Year Adjustment x Levelization Adjustment x Rated Criteria Adjustment – System Value Constant[68]

Where:

The Rated Criteria Adjustment = 1 – 0.4 x Total Point Score ÷ 100

And where the IESO once again uses a set of assumptions that applicants are made aware of in advance of proposal submission.

[68] IESO. *Addendum 2 – LRP I RFP.* July 2013.

Figure 31. Additional assumptions disclosed as part of LRP I

Renewable Fuel	On-Peak Factor	Off-Peak Factor	Dollar-Year Adjustment	Levelization Adjustment	System Value Constant
Bioenergy (Renewable Biomass, Biogas, and Landfill Gas)	0.43	0.57	0.94	0.87	Cdn.$57
On-Shore Wind	0.41	0.59	0.92	0.87	Cdn.$48
Solar (Rooftop Solar and Non-Rooftop Solar)	0.69	0.31	0.94	0.84	Cdn.$76
Waterpower	0.43	0.57	0.85	0.80	Cdn.$61

(*Source: LRP I RFP)*

Each project whose submitted weighted price does not exceed the maximum weighted price administratively set by the IESO (below) will be ranked from lowest to highest Evaluated Proposal Price to establish an "initial stack."[69]

The final stack is determined following completion of connection availability in the initial stack up to the target capacity (as set by the LTEP) for each fuel type.

Other mechanisms

In addition to the evaluation of prices, there are several other mechanisms that support a competitive outcome. First there is a bid deposit of Cdn$10,000 to participate in the process, which is not refundable. This encourages only serious bidders to participate. Second, winning bidders are required to post a contract security from the start of the contract until they achieve commercial operation. That amount is set at Cdn$50,000/MW of contract capacity. That deposit is returned to the developer once the project is operational. Finally, there is a third party evaluation team and a "Fairness Advisor" who are all party to the process and provide a written statement subsequently that the process was conducted in a fair and transparent manner.

[69] Ibid.

7.3 Transmission

Transmission expansion is not part of the procurement process. The LRP process does not allow any particular project to pass the connection availability test if the Transmission System would require upgrades in order to accommodate its connection. The IESO's LRP I RFP Backgrounder on Connection contains the following comment regarding Transmission:

> "Allowing generator paid upgrades to the Transmission System/IESO-Controlled Grid introduces uncertainty and risk into the procurement and project development processes. These upgrades generally carry higher connection costs as well as increase the time needed to complete construction and connection of a Large Renewable Project. These factors can lead to higher rates of project attrition. Upgrades to the existing Transmission System/IESO-Controlled Grid can be affected by the number, size, type and location of the generators that will ultimately connect. The scope of the upgrades is often very difficult to establish in the context of a single-connection proposal." [70]

To address issues of system connection availability, the IESO published a connection availability test (called "Transmission Availability Test" or "TAT" and "Distribution Availability Test" or "DAT"). The TAT/DAT tables act as a guideline for both applicants and the IESO in assessing a project's ability to connect given its proposed location. The TAT/DAT tables were accompanied by connection costs so that applicants were given greater clarity on the overall process of connecting their project. Having these test tables and cost estimates published prior to the RFQ stage was a key element of the procurement program.

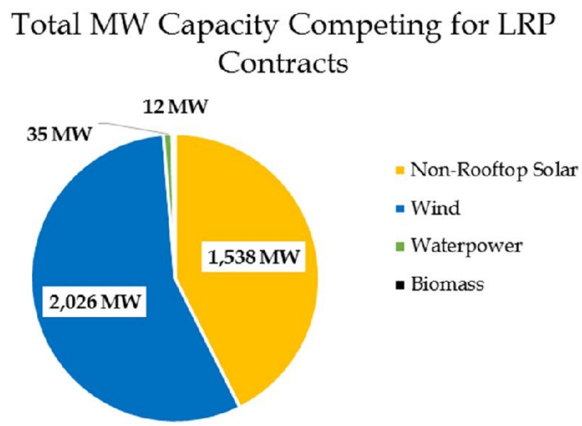
7.4 Outcomes

42 applicants were successful in the RFQ stage; they subsequently submitted a total of 103 project proposals in the RFP process, totalling 3,611 MW. The entire RFQ and RFP process has taken just under two years though the first year of that was due to the development of the RFP and contracts and stakeholder facilitation. Out of 103 Proposals, 16 were successful in securing long term IESO contracts. The 16 contracts offered represent 455 MW of renewable energy capacity. The results include:

- 5 wind contracts totaling 300 MW, with a weighted average price of $85.94/MWh and an approximate weighted price range of $64.50 to $105.50/MWh;
- 7 solar contracts totaling 140 MW, with a weighted average price of $156.67/MWh and an approximate weighted price range of $141.50 to $178.50/MWh; and
- 4 hydroelectric contracts totaling 16 MW, with a weighted average price of $175.92/MWh and an approximate weighted price range of $173.50 to $177.00/MWh.

[70] IESO. *LRP I RFP Backgrounder – Connection.* March 10, 2015.

Figure 32. Total MW capacity competing in the RFP stage



In addition, the IESO has announced the launch of the LRP II stakeholder consultation in April 2016. This process will be primarily focused on lessons learned from the first large renewable procurement to inform the next LRP. The IESO posted a stakeholder engagement plan on March 1 which outlines three phases: "*Phase I: Review of LRP I Process, Phase II: Feedback on a draft LRP II Request for Qualifications (LRP II RFQ), and Phase III: Feedback on draft LRP II Request for Proposals.*"[71]

7.5 Strengths and weaknesses

The Large FIT program was heavily criticized by media and the public alike for its lucrative prescriptive prices and was often blamed for increasing electricity prices in Ontario. The Ministry wanted to continue to promote renewables but in a way that resulted in more competitive outcomes and lower costs to ratepayers. Employing a consultative and collaborative approach to the design of the procurement helped the IESO involve the communities that previously critiqued them. By engaging communities and employing a competitive price evaluation phase, the IESO enhanced transparency and competition in the LRP.

The Ministry placed a great deal of importance on engaging the local municipality and community as evidenced by the rated criteria adjustment feature. This provided a financial incentive to bidders to engage with local and Aboriginal communities. That engagement was only required as part of the RFP process and it is unclear how long lasting or how deep that engagement really was.

[71] IESO. *Large Renewable Procurement II (LRP) Stakeholder and Community Engagement Plan.* March 1, 2016.

7.6 Implications for Alberta

- With hindsight, Ontario's experience phasing out coal was easier than anticipated given that its electricity demand decreased at a similar time due to economic conditions. While electricity demand is not growing as quickly as it was, Alberta will still need to ensure that its procurement design lends itself to flexible targets so that it can respond to evolving supply-demand conditions.

- Ontario's relatively sophisticated approach to transmission integration is also an approach that merits greater assessment and consideration for its relevance to the Alberta market. It is pragmatic to consider that transmission expansion may take more time that anticipated and can hinder the renewable development process. Providing a way for developers to test their ability to interconnect as part of the procurement process helps address that though the AESO would need to ensure it has the resources to do so. Finally, Ontario's approach to selecting the lowest cost project by interconnection point seems particularly effective.

- Ontario's transparency in explaining how bids would be evaluated and providing the underlying assumptions as part of the RFP process are certainly a model for other jurisdictions trying to achieve a successful competitive outcome.

- Finally, Ontario has put in place a permanent feedback loop for its procurement process with a goal of continuously improving it. This may be time-consuming but does provide useful feedback to improve the process and there may be quicker ways to harness that valuable feedback in the Alberta context, such as a one-time technical conference or the ability to submit written feedback.

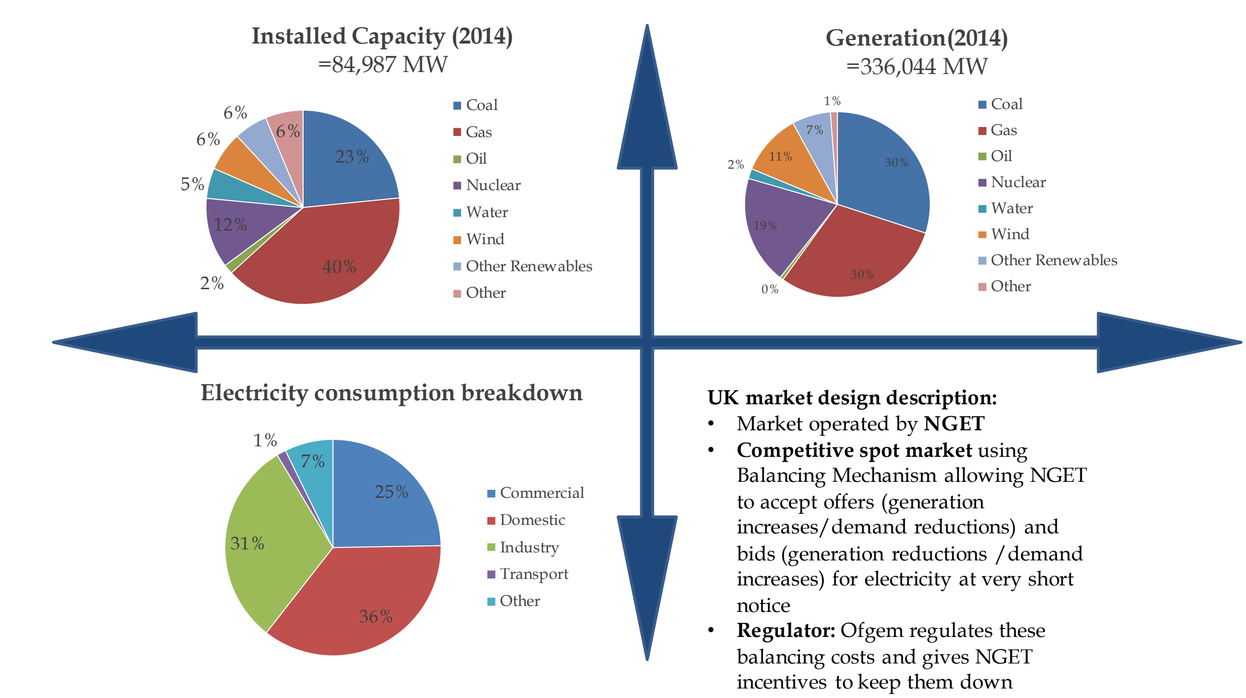
8 United Kingdom Contract for Differences

8.1 Context

8.1.1 UK market characteristics

The UK has an installed capacity of 84,987 MW,[72] with gas and coal generating 60% of the total electricity in 2014. Electricity consumption is relatively balanced, with 36% of total consumption from households, 31% from industry, and 25% from commercial users.

Figure 33. Overview of United Kingdom electric power market characteristics



Source: UK Department of Energy & Climate Change, Ofgem

The UK has a wholesale electricity market where generators sell electricity to suppliers through bilateral contracts, over-the-counter trades, and spot markets. It has been open to competition since 1990 with the creation of the Electricity Pool ("Pool"). Electricity can also be imported or exported through interconnectors with Britain and France, the Netherlands, and Ireland. As the system operator, National Grid Electricity Transmission ("NGET") is the real-time "residual balancer" of the electricity system, and takes actions to ensure that electricity supply and demand

[72] Gov.uk. "*DUKES 2015 Chapter 5.*" <https://www.gov.uk/government/uploads/system/uploads/attachment_data/file/447632/DUKES_2015_Chapter_5.pdf>

match on a second-by-second basis using tools like the Balancing Mechanism which allows NGET to accept offers (generation increases/demand reductions) and bids (generation reductions /demand increases) for electricity at short notice.[73]

8.1.2 UK renewable energy targets

The European Union ("EU") has set a target of producing 20% of its energy from renewable sources by 2020 and 40% by 2030. While each country in the EU has its own target to meet, the UK has been asked to procure 15% of its energy consumption from renewable sources in 2020. The DECC plans to achieve it by generating 30% of electricity, 12% of heat and 10% of transport energy from renewable sources.[74]

Overview of UK's CfD Program:

- DECC establishes procurement targets, designs the procedures and oversees the overall process
- National Grid serves as the procurement manager of the process
- CfD structure means that generators are paid difference between their bid strike prices as compared to a market reference process
- Eligible renewables within budgeted technology pots compete against one another on technology specific "strike prices"
- Winners from each technology pot share same clearing strike prices for each delivery year
- Competitive results with lower-than-original strike prices indicate a successful auction

To help the UK meet the 2020 target in a cost effective and sustainable way, DECC developed the UK Renewable Energy Roadmap, which focuses on eight key technologies: onshore wind, offshore wind, marine energy, biomass electricity, biomass heat, ground source and air source heat pumps and renewable transport, as shown below in Figure 34.[75]

The UK has several policies in place to try to increase the generation of renewable electricity. The UK is one of the many EU countries who have adopted the EU Emissions Trading System ("ETS"). The UK also adopted a Carbon Price Support mechanism starting in 2013 to support investment in low-carbon generation. Feed in tariffs are provided to promote small-scale renewables. The UK used a Renewables Obligation ("RO") as its main support mechanism for larger renewable electricity projects, which involved providing tradable green certificates to

---

[73] Ofgem. "*The GB electricity wholesale market.*" <https://www.ofgem.gov.uk/electricity/wholesale-market/gb-electricity-wholesale-market>

[74] Sam Ashworth-Hayes. "*The UK's renewable energy target.*" November 03, 2015. <https://fullfact.org/economy/uks-renewable-energy-target/>

[75] DECC. "*UK Renewable Energy Roadmap.*" July 2011. <https://www.gov.uk/government/uploads/system/uploads/attachment_data/file/48128/2167-uk-renewable-energy-roadmap.pdf>

operators of accredited renewable generating stations for the eligible renewable electricity they generate.[76] The RO was not viewed as an effective program[77] and the UK initiated a different approach to incentivizing the development of renewable energy, the Contract for Differences, which is the subject of our case study.

Figure 34. Technology breakdown for central view of deployment in 2020 (TWh)

	Central range for 2020 (TWh)
Onshore wind	24-32
Offshore wind	33-58
Biomass electricity	32-50
Marine	1
Biomass heat (non-domestic)	36-50
Air-source and Ground-source heat pumps (non-domestic)	16-22
Renewable transport	Up to 48 TWh
Others (including hydro, geothermal, solar and domestic heat)	14
Estimated 15% target	234

Source: UK Renewable Energy Roadmap

8.2 Key process design attributes

The CfD is part of the comprehensive UK Electricity Market Reform initiated by the DECC in November 2012. CfDs are designed to give renewable investors the certainty they need to invest in low carbon electricity generation, attract greater investment in low-carbon generation, and subsequently reduce the UK's carbon emissions. The first allocation round opened on 16 October 2014 and concluded on 27 March 2015.

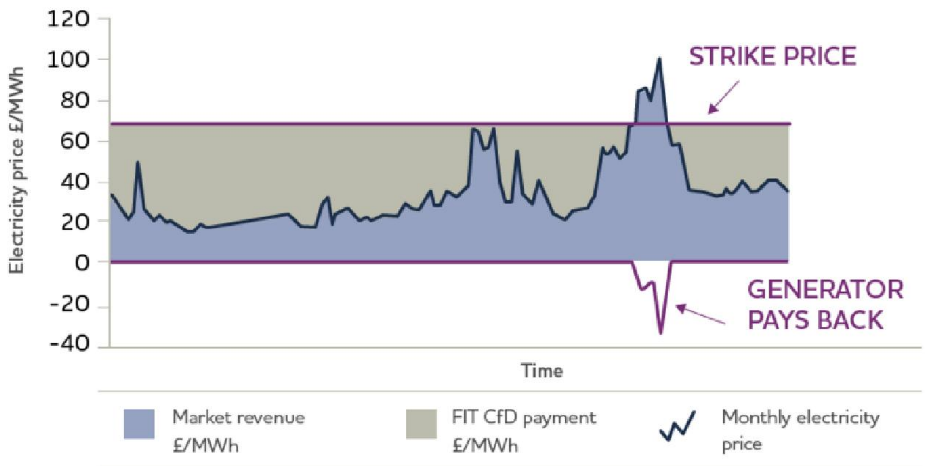
A CfD is a contract between a low carbon electricity generator and the Low Carbon Contracts Company ("LCCC"), a private company owned by DECC. The generator will be paid the difference between the "strike price" – a price for electricity reflecting the cost of investing in a particular low carbon technology – and the "reference price"– a measure of the average market price for electricity in the national market. When the market price is above the contracted strike price, a payment is made by the generator to the LCCC for the surplus revenue; when the wholesale electricity price is below the contracted strike price, a payment is made by the LCCC

[76] Ofgem. <https://www.ofgem.gov.uk/environmental-programmes/renewables-obligation-ro>

[77] According to UK energy secretary Amber Rudd, the UK wants a transition from RO to CfD because "we want to help technologies stand on their own two feet, not encourage a reliance on public subsidies." Tisheva, Plamena. *OVERVIEW - The abrupt change on UK renewables policy*. February 29, 2016. <http://renewables.seenews.com/news/overview-the-abrupt-change-on-uk-renewables-policy-515044>. Also refer to DECC's "*Government Response to the consultations on the Renewables Obligation Transition and on Grace Periods.*" <https://www.gov.uk/government/uploads/system/uploads/attachment_data/file/289076/Transition_and_Grace_Periods_Government_Response_-_12_Mar_2014.pdf>

to the generator for the shortfall.[78] It gives greater certainty and stability of revenues to electricity generators by reducing their exposure to volatile wholesale prices, while protecting consumers from paying for higher support costs when electricity prices are high.[79]

Figure 35. Illustrative diagram showing CfD payment flows depending on electricity prices



Source: UK Government White Paper, July 2011. Licensed under the Open Government licence v1.0[80]

8.2.1 Establishing resources needs

DECC sets the targets for CfD procurement. The budget for the technology pots in the current round is as follows:

Pot 1 (established technologies, such as onshore wind and solar): £50 million for projects commissioning from 2015/16, and an additional £15 million (i.e. £65 million in total) for projects commissioning from 2016/17 onwards.

Pot 2 (less established technologies, such as offshore wind and biomass plants for combined heat & power ["CHP"]): £155 million for projects commissioning from 2016/17 onwards, and an additional £105 million (i.e. £260 million in total) for projects commissioning from 2017/18 onwards. This demonstrates the Government's commitment to helping these technologies become as competitive as the more established low carbon generation sources.

Pot 3 (biomass conversion): No budget released in this allocation round but this does not preclude budget being allocated to this pot in future rounds.

---

[78] Oxera Consulting. "*CfDs: the (strike) price is right?*" September 2015. <http://www.oxera.com/Latest-Thinking/Agenda/2015/CfDs-the-(strike)-price-is-right.aspx>

[79] Gov.uk "*Electricity Market Reform: Contracts for Difference.*" <https://www.gov.uk/government/collections/electricity-market-reform-contracts-for-difference>

[80] EMR Settlement Limited. <https://emrsettlement.co.uk/about-emr/contracts-for-difference/>

Figure 36. Revised CFD Budget Release for 2014 Allocation Round (Figures are total support payments available in a given year; Unit: £ millions 2011/12 prices)

	Delivery Year					
£m (2011/12 prices)	15/16	16/17	17/18	18/19	19/20	20/21
CFD Budget (2014 release)	50	220	325	325	325	325
Pot 1 (established technologies)	50	65	65	65	65	65
Pot 2 (less established technologies)		155	260	260	260	260

Source: DECC

Supplemental Requirements

The other requirements are specific to each technology. For example, offshore wind projects must have a capacity of no greater than 1,500 MW and, if phased, the first phase must represent at least 25% of the total capacity of the CfD Unit after all phases are completed.

8.2.2 Managing procurement process

Before bidders submit their applications in the CfD process, they are required to prepare and submit a "Supply Chain Plan" to DECC. This document includes information about the project, the team proposing the project, and other relevant information. In addition, this application includes documentation to demonstrate compliance with the eligibility requirements of the CfD, such as (but not limited to): connection agreements; supplemental requirements for offshore phased projects; and planning permissions, which are to be assessed by National Grid. Projects need to be considered "eligible" in order to submit financial bids.

The CfD reduces the risks faced by low-carbon generators by paying a variable top-up between the market price and a fixed price level, known as the 'strike price.' While reducing generators' exposure to volatile and rising fossil fuel prices, the CfD also protects consumers by ensuring that generators pay back when the price of electricity goes above the strike price. This reduction in risk and increased level of certainty reduces the borrowing costs that investors face.

The administrative strike prices are set for all eligible technologies, and are listed in Figure 37. To take into account that the expected cost decreases as technologies become more established, the administrative strike prices ("ASP") fall over time.

Figure 37. ASPs for all eligible technologies (£/MWh)

	2014/15	2015/16	2016/17	2017/18	2018/19
Advanced Conversion Technologies (with or without CHP)	155	155	150	140	140
Anaerobic Digestion (with or without CHP)	150	150	150	140	140
Dedicated Biomass (with CHP)	125	125	125	125	125
Energy from Waste (with CHP)	80	80	80	80	80
Geothermal (with or without CHP)	145	145	145	140	140
Hydro	100	100	100	100	100
Landfill Gas	55	55	55	55	55
Sewage Gas	75	75	75	75	75
Onshore Wind	95	95	95	90	90
Offshore Wind	155	155	150	140	140
Biomass Conversion	105	105	105	105	105
Wave	305	305	305	305	305
Tidal Stream	305	305	305	305	305
Large Solar Photo-Voltaic	120	120	115	110	100
Scottish Islands Onshore				115	115

Source: DECC[81]

The implementation of the CfD procurement process is carried out by several organizations. Generally speaking, DECC is the ultimate designer and decision maker of the CfD process. DECC owns the LCCC as the CfD counterparty, but National Grid, the transmission company, runs the CfD process and reports results to DECC, and Ofgem is the third-party regulator ensuring the efficiency and competitiveness of the whole process. Detailed responsibilities of each organization are described below.

DECC

As the designer of the CfD process, DECC has general responsibility for designing and overseeing the RFP process. Its responsibility includes:

- setting the terms of the CfD contract;

[81]DECC. "*Investing in renewable technologies – CfD contract terms and strike prices.*" December 2013. <https://www.gov.uk/government/uploads/system/uploads/attachment_data/file/263937/Final_Document_-_Investing_in_renewable_technologies_-_CfD_contract_terms_and_strike_prices_UPDATED_6_DEC.pdf >

- determining objectives for the allocation system;
- setting eligibility criteria, auction rules, and details of the allocation process;
- approving supply chain plans and whether to proceed with, rerun or terminate an allocation round;
- reviewing and approving the Low Carbon Contracts Company's operational budget and setting the operational cost levy rate to cover this in the CfD;
- announcing allocation rounds and the budget for allocation rounds; and
- is the sole shareholder of the LCCC.

National Grid

As the CfD procurement manager, National Grid is responsible for: (i) assessing the eligibility of applications for generic CfDs; (ii) valuing all applications and assessing whether an auction process is required to decide which applicants should be offered a CfD; (iii) running the CfD allocation process; (iv) providing the Low Carbon Contracts Company with the information necessary to offer a CfD; and, (v) conducting analysis to support the Government's setting of administrative strike prices.[82]

LCCC

As the counterparty to the CfDs, LCCC is owned by DECC and acts as a facilitator of the procurement. It manages the contracts and is responsible for payments. It also forecasts, calculates and collects payments, holds collateral from suppliers/generators, takes action to recover debts owed by electricity suppliers and generators, and mutualizes any unpaid debts.[83]

Ofgem

Being a regulator of the electricity sector in the UK, Ofgem ensures that the CfD procurement process is carried out according to regulation and addresses any concerns regarding disputes or market collusion.

---

[82] LCCC. "*Electricity Market Reform Contracts for Difference- GB Implementation Plan.*" July 24, 2014. <https://www.gov.uk/government/uploads/system/uploads/attachment_data/file/337242/CfD_Implementation_Plan_GB_Updated_from_08_April_2014.pdf>

[83] DECC. "*Low Carbon Contracts Company and Electricity Settlements Company operational costs 2016/17.*" <https://www.gov.uk/government/uploads/system/uploads/attachment_data/file/474061/LCCC_ESC_2016-17_operational_costs_condoc.pdf>

8.2.3 Ensuring competitive outcomes[84]

Bid evaluation process

The desired result of the CfD allocation is largely technology-neutral (subject to Minima and Maxima requirements if relevant[85]) and, ideally, selects the projects with lower costs as revealed through the bidding of the "strike price." If the total value of applications does not exceed the available budget, all applied projects will receive the Administrative Strike Prices ("ASP") set by DECC as announced at the beginning of the procurement.

However, if the total value of applications exceeds the available budget, as is usually the case, after the eligible generators submit a sealed bid, they are ranked from the lowest to highest strike price subject to budget constraint and any technology specific minimum acquisition thresholds. The auction is closed when the next bid causes that delivery year's budget to be exceeded or when the capacity threshold is reached. When any capacity Minima for particular technologies are binding, a separate auction with bids from only the relevant technology is run before running the general auction until the Minima threshold is reached. Those who are not accepted in the Minima auction are included in the general auction.

All projects within that delivery year are awarded a final clearing price equal to the strike price of the last approved project, which is known as a "uniform price" auction. If winning applicants fail to achieve milestone requirements, or drop out early, they may be prevented from participating in future auctions on that generating site.[86]

A more detailed description of the CfD process is provided below broken into the three main phases of the process:

Step 1: Submitting sealed bids on strike prices

Applicants submit a sealed bid for each project stating: (i) the Applicant's proposed Strike Price that it will accept for each megawatt hour of Metered Output, which must not be more than the applicable ASPs, including a number of flexibility bids;[87] (ii) the Applicant's Target

---

[84] DECC. "*Contract for Difference: Final Allocation Framework for the October 2014 Allocation Round.*" September 1, 2014. <https://www.gov.uk/government/uploads/system/uploads/attachment_data/file/404419/Contract_for_Difference_Final_Allocation_Framework_for_the_October_2014_Allocation_Round_1_September_2014.pdf>

[85] The government usually sets Minima requirements for technologies at an earlier stage of development and Maxima requirements for technologies at a more mature stage. Considering that a widespread use of Maxima and Minima would undermine the delivery of a cost-effective technology mix and lead to a less-efficient use of available budget, DECC only put in place Minima requirements for wave and tidal stream technologies in the first competitive round.

[86] Oxera Consulting. "*CfD auctions, bidding strategies, and insights from auction theory.*" September 2014. <http://www.oxera.com/Latest-Thinking/Agenda/2014/CfD-auctions,-bidding-strategies,-and-insights-fro.aspx>

[87] Applicants may submit up to 10 flexibility bids. Flexibility bids allow the generators to make multiple bids pertaining to the same project by varying the strike price to account for alternative (lower) capacity levels or (later) delivery years. If a bid exceeds

Commissioning Date and start date of the Target Commissioning Window; and (iii) the capacity of the CfD Unit.

Only one sealed bid (and one Strike Price) for the same first Delivery Year and for the same capacity is allowed for each application. Additional special requirements may apply to specific technologies.

Step 2: Applications Valuations

Based on the strike price bids submitted by all the Applicants, National Grid determines the Applications Valuations in respect of each of the years specified in the Budget Profile, using the *Valuation Formula*.[88] For the 2014 Allocation Round, Applications were valued using 2012 prices. National Grid must determine the Applications Valuations within one working day after the Application Closing Date for all applications. This step basically estimates how much funding is expected to be spent by LCCC based on the difference between the ASPs and reference prices which are set in the terms as corresponding forward market indices.[89]

Step 3: Ranking and accepting bids sequentially subject to budget and capacity Minima/Maxima constraints

In a normal case where the total value of applications exceeds the available budget, auctions will be held. As discussed earlier, any technologies that are subject to a capacity minimum requirement are dealt with separately.

In the general auctions, bids are ranked from lowest to highest strike price. Starting with the bids with the lowest strike price, bids from different technologies are accepted sequentially until the next bid under consideration causes that delivery year's budget to be exceeded, or some other capacity threshold to be met. Note that in the evaluation of the impact on the Budget Profile at this stage, the relevant clearing price is used as the Reference Prices to analyze the "expected" value of each bid.

When this general auction is closed, all projects within that delivery year are awarded at the final clearing prices equaling to the strike price of the last approved project. In other words, for the

---

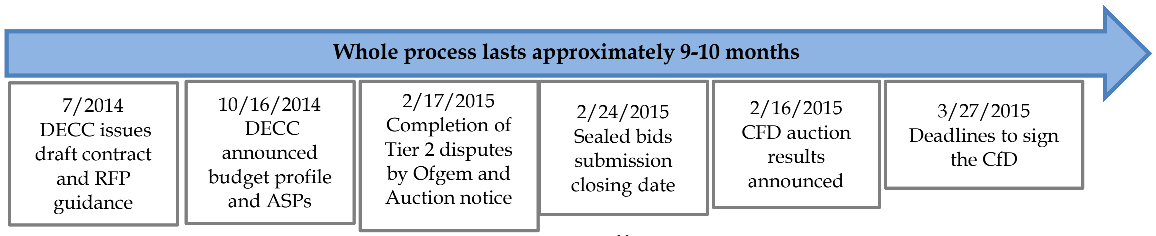
the budget in any given delivery year, and the next highest bid is a flexibility bid from the same application, the flexibility bid is accepted if it prevents the budget being breached. If the budget is still breached then this process continues until all flexibility bids are exhausted and the auction for a given delivery year is closed. As soon as one of a group of flexible bids is accepted, all the other bids of the group are removed from the auction process. <http://www.oxera.com/Latest-Thinking/Agenda/2014/CfD-auctions,-bidding-strategies,-and-insights-fro.aspx>

[88] "Valuation Formula" means: $\text{Budget impact}_{s,yr,p} = (\text{Strike Price}_{cy,t} - \text{Reference Price}_{yr}) * \text{Load Factor}_{t,yr} * \text{YR1F}_{s,c,p} * \text{Capacity}_{s,p} * (\text{Days}_{yr} * 24) * (1 - \text{TLM}_{yr}) * \text{RQM}_t * \text{CHPQM}_s$, refer to schedule 2 in <https://www.gov.uk/government/uploads/system/uploads/attachment_data/file/404419/Contract_for_Difference_Final_Allocation_Framework_for_the_October_2014_Allocation_Round_1_September_2014.pdf>

[89] Please refer to the Market Reference Price section in Update on Terms for the Contracts for Difference. <https://www.gov.uk/government/uploads/system/uploads/attachment_data/file/267735/EMR_-_Update_on_Terms_for_the_Contract_for_Difference_v8.pdf>

winning projects within the same technology pot, the clearing strike prices are the same for each delivery year.

Figure 38. Timeframe for UK CFD procurement



Source: National Grid. "Contracts for Difference Round Guidance"[90]

Other mechanisms

There is no bid deposit requirement for CfD. There is also no explicit contract security for the winning bidder, however numerous contractual requirements are activated once the winning bidder signs the CfD contract which ultimately do have a similar impact on the winning bidder. Those include:

- obligation to provide the CfD Counterparty with information about progress to commissioning;
- a requirement to demonstrate that a substantial financial commitment has been entered into within a year of contract signature. This includes demonstrating that they have spent 10% of total project pre-commissioning costs or that they have entered into other commitments that are a proxy for spending money; and
- developers that do not meet these relevant requirements will be liable to have their CFDs terminated, allowing the budget to be reallocated to new applicants.

8.3 Transmission

No specified policies apply to CfD Applicants except that they are responsible for connecting their renewable generators to the network upon their success in the procurement.[91] In the procurement application, an Applicant needs to prove: (i) that at least 75% of the Initial Installed Capacity Estimate of the CfD in application is secured with the right to connect to the system if a Direct Connection applies to the corresponding unit; or (ii) that he/she is the owner of the

[90] National Grid. October 3, 2014. <https://www.emrdeliverybody.com/Contracts%20for%20Difference%20Document%20Library/CFD%20Round%20Guidance.pdf>

[91] Please refer to Rule 4 Connection Agreements in the Framework.

relevant network or has already made the agreement with the network owner securing the connection rights for the CfD in application.

8.4 Outcomes

A total of 27 projects were successful in the first round auction and 25 went on to sign contracts,[92] totaling almost 2 GW of capacity.[93] In February 2015, the DECC published the outcome of the first allocation round, coinciding with National Grid's notification of winning applicants. Through February 2016, four projects totaling 39.45 MW that were allocated CfDs in 2015 have passed their milestone requirement.[94]

Figure 39. Information on the successful applicants, as follows – strike prices are in 2012 prices[95] (£/MWh)

Project Name	Developer	Technology	MW	Strike Price (£)	Delivery Year
BHEG Walsall	BH EnergyGap (Walsall) Ltd	Advanced Conversion Technologies	26.0	114.39	2018-2019
Energy Works (Hull)	Energy Works (Hull) Limited	Advanced Conversion Technologies	25.0	119.89	2017-2018
Enviroparks Hirwaun Generation site	Enviroparks Operations Ltd	Advanced Conversion Technologies	11.0	119.89	2017-2018
Wren Power and Pulp	Gent Fairhead & Co. Ltd	Energy from Waste with CHP	49.8	80.00	2018-2019
K3 CHP Facility	K3CHP Ltd	Energy from Waste with CHP	45.0	80.00	2018-2019
EA 1	Scottishpower Renewables (UK) Limited	Offshore Wind	714.0	119.89	2017-2018
Neart na Gaoithe	Neart na Gaoithe Offshore Wind Limited	Offshore Wind	448.0	114.39	2018-2019
Dorenell Wind Farm	Dorenell Limited	Onshore Wind	177.0	82.50	2018-2019
Kype Muir Wind Farm	Banks Renewables (Kype Muir Wind Farm) Limited	Onshore Wind	104.0	82.50	2018-2019
Clocaenog Forest Wind Farm	RWE Innogy UK Limited	Onshore Wind	96.0	82.50	2018-2019
Middle Muir Wind Farm	Banks Renewables (Middle Muir Wind Farm) Limited	Onshore Wind	60.0	82.50	2018-2019
Brenig Wind Farm - Brenig Wind	Brenig Wind Limited	Onshore Wind	45.0	79.23	2016-2017
Mynydd Y Gwair Wind Farm	RWE Innogy UK Limited	Onshore Wind	40.0	79.99	2017-2018
Nanclach Wind Farm	Nanclach Limited	Onshore Wind	39.1	82.50	2018-2019
Solwaybank Wind Farm	Solwaybank Energy Limited	Onshore Wind	37.5	82.50	2018-2019
Sneddon Law Community Wind Farm	Sneddon Law Community Wind Company Limited	Onshore Wind	37.5	79.99	2017-2018
Coire Na Cloiche Windfarm	Coire Na Cloiche Windfarm LLP	Onshore Wind	30.0	82.50	2018-2019
Bad a Cheo Wind Farm	RWE Innogy UK Limited	Onshore Wind	29.9	82.50	2018-2019
Tralorg Wind Farm	PNE WIND UK Ltd	Onshore Wind	20.0	82.50	2018-2019
Moor House Wind Farm	Banks Renewables (Moor House Wind Farm) Limited	Onshore Wind	16.4	82.50	2018-2019
Achlachan Wind Farm	Achlachan Wind Farm LLP	Onshore Wind	10.0	82.50	2018-2019
Common Barn Wind Farm	Common Barn Wind Farm Ltd	Onshore Wind	6.2	82.50	2018-2019
Wick Farm Solar Park (contract not signed)	Hadstone Energy Limited	Solar PV	19.1	50.00	2015-2016
Charity Farm	Lightsource SPV136 Limited	Solar PV	14.7	79.23	2016-2017
Royston Solar Farm (contract not signed)	ROYSTON SOLAR FARM LIMITED	Solar PV	13.8	50.00	2015-2016
Netley Landfill Solar	REG Netley Solar Ltd	Solar PV	12.0	79.23	2016-2017
Triangle Farm Solar Park	Cambridgeshire County Council	Solar PV	12.0	79.23	2016-2017
Total Capacity from all successful bidders who have signed contracts			**2106.0 MW**		

[92] Wick Farm Solar Park and Royston Solar Farm will not proceed as originally planned because that the wholesale cost of electricity is set at the same level as the winning strike price of £50/MWh. The projects are just not feasible at such a low price.

[93] DECC. "*Electricity Market Reform Annual Update 2015.*" October 2015.

[94] Tisheva, Plamena. "*First 4 projects meet CfD milestone in UK.*" February 17, 2016. <http://renewables.seenews.com/news/first-4-projects-meet-cfd-milestone-in-uk-513543>

[95] DECC. "*Contracts for Difference (CFD) Allocation Round One Outcome.*"

The outcome of the CfD auction confirmed that the costs of the winning projects were considerably lower than the administratively determined costs. For example, approximately 1,910 MW was allocated to wind farms. For onshore wind farms the lowest strike price was £79.23/MWh, around 17% lower than the Administered Strike Price ("ASP") of £95/MWh for a project to be delivered in 2016/17. Similarly, offshore wind projects had a minimum clearing price of £119.89/MWh, around 18% lower than the ASP of £140/MWh for projects to be delivered in 2017/18.

8.5 Strengths and weaknesses

The CfD process has so far been regarded positively. The first round of auctions already achieved sufficient renewable generation to meet or even exceed the government's 2020 renewables target. In addition, the auction clearing strike prices were significantly lower than the ASP, indicating that the auction mechanism was successful in delivering a competitive outcome with only 27% of applicants receiving a contract through the auction.

Strengths of the CfD are considered to be:

- the procurement approach favors projects that are more cost-effective;
- different original ASPs and Capacity Minima and Maxima requirements in the auction for different types of technologies ensures a more diversified portfolio of renewable technologies than might otherwise have occurred;
- reducing developers' exposure to volatile wholesale prices, and at the same time protecting consumers from paying for higher support costs when electricity prices are high; and
- the selection process is highly quantified and objective.

After the first round allocation, DECC sets out the intention to make the following key changes to the CfD procurement process:[96]

- allow unincorporated joint ventures to enter into a CfD, which increases the potential bidding pool;
- ensure that generators do not have an incentive to generate electricity under negative prices;
- confirm that a simultaneous application to the Capacity Market and CfD auctions cannot be made;

---

[96] DECC. "*Electricity Market Reform Annual Update 2015*". October 2015. <https://www.gov.uk/government/uploads/system/uploads/attachment_data/file/468337/EMR_Annual_Update_2015_web_accessible_version.pdf>

- ensure that a distinction is made between sensitive price information and non-sensitive price information set out in a sealed bid submission; and,
- amendments to ensure that the connection requirements applicable to private network operators were set out in secondary legislation.

Critiques of the program include:

- The CfD construct is somewhat less well known and more complex than a procurement process that results in a standard PPA, meaning that bidders will have to learn this structure and become comfortable with the contract.[97]
- The lack of bid and security deposits is unusual and it remains to be seen if this affects the timeliness of projects coming on-line as promised or whether there will be a larger percentage of projects that do not get developed.
- The reference price is not necessarily the actual market price, which might result in losses to the winning renewable projects or the LCCC (which is ultimately the government) depending on the actual market prices of electricity.98
- The efficacy of the clearing strike prices from the auctions depends heavily on the level of competition in the market. When the market is highly concentrated with a few large market players, those who are able to bid for more than one CfD might be able to influence the clearing strike price by bidding less aggressively, resulting in higher-than-efficient clearing strike prices;99
- when the market is highly competitive and the bids are sealed, successful bidders are likely to experience the winner's curse as they have an incentive to bid for lower-than-reasonable strike prices just to win the procurement without the knowledge of competitors' cost valuations.

8.6 Implications for Alberta

- The CfD structure is an elegant solution to the challenge of developers needing a more predictable revenue stream and for procuring entities wishing to minimize cost exposure. However, to implement such a structure is not a small undertaking. The contracts themselves are more complex and the process of reconciling required payments each year

[97] Note that it was used in Ontario for some conventional plant contracts.

[98] Pollitt, Michael. "*Wholesale and retail electricity market reforms in the UK: What not to do*." March 20, 2013. <http://www.eprg.group.cam.ac.uk/wp-content/uploads/2014/01/UpdateonUKelectricitymarket200313.pdf>

[99] Oxera Consulting. "*CfD auctions, bidding strategies, and insights from auction theory*." September 2014. <http://www.oxera.com/Latest-Thinking/Agenda/2014/CfD-auctions,-bidding-strategies,-and-insights-fro.aspx>

(or each month as the case may be) is more onerous and requires more oversight and resources.

- The UK process has been reasonably successful at getting its desired quantity of renewables contracted. It still remains to be seen if those projects come on line as anticipated and what the full economic impacts of those contracts are.

- As with Ontario, the process of providing the assumptions and not to exceed price caps help inform bidders and ultimately make the bidding process successful. That is, however, premised on setting realistic, current thresholds that are achievable by a significant number of developers.

- The UK's declining strike price over time, as seen in Figure 37, is a model that Alberta may also want to consider given that it may be procuring renewables over several years. This sends a clear signal to the market about the procurement manager's expectations of technology cost development and the competitiveness of future processes.

9 Other specific AESO questions

This section provides responses to several specific clarifying questions asked by the AESO.

9.1 Centralized procurement

Did any of the jurisdictions employ both a centralized procurement and a financial incentive approach?

Any jurisdictions that utilize a centralized procurement approach in the US would fall into this category as all qualifying renewable energy projects would be able to take advantage of both the federal financial incentives (such as the production tax credit, investment tax credit, and/or accelerated depreciation). Thus, examples of jurisdictions that benefit from using both a centralized procurement and a financial incentive include New York and California. Note that the budget sources for these incentives are different, with state entities funding any contracts granted under a centralized procurement and with the federal US Treasury providing the financial benefits (though reduced tax income) of financial incentives.

Has any central procurement agency procured only the "green attribute" as opposed to "capacity plus energy plus green attribute," i.e., a bundled product?

Historically New York's centralized Main Tier procurement, discussed in Section 6, has only procured the environmental attributes of the renewables. However, as is discussed in that section, there have been concerns that that approach has not been effective and discussions are underway for that centralized procurement to transition to a bundled product that includes the underlying commodity as well as the renewable attributes.

Has any jurisdiction only paid a "premium", besides a contract for differences?

The two structures that are usually used to pay a "premium" are the procurement of just the environmental attributes, as seen in New York, or through the use of a Contract for Differences as seen in the UK. Similarly, France has recently moved to a "top up" approach for incentivizing its large renewable energy projects, which are required to sell on the wholesale market (although off shore wind is exempt from this requirement).

9.2 Quota obligation programs

Has anyone ever put the quota obligation on generators, the government or a government authority?

In markets where the utility is no longer vertically integrated, it is most common for the quota obligation to be on the load serving entity, whether that be a retailer, distributor, or a utility. That is the case in most US RPS structures, for example.

In markets that have not deregulated and where there is a vertically integrated utility or a prominent centralized buyer, the quota obligation is sometimes put on that utility or the single buyer, as seen for example with Gestori Servizi Energetici ("GSE") in Italy or Moroccan Agency for Solar Energy ("MASEN") in Morocco. Note that quota obligations are usually defined in terms of a percentage of total sales or consumption, although in some cases can be defined as a targeted amount of capacity, as was seen in the Texas market. In Texas, that capacity figure was effectively "translated" to a pro rata share requirement for load serving entities based on each entity's retail sales as compared to total retail sales.

How have other jurisdictions managed a longer term quota? Is it broken into shorter term targets?

Certain jurisdictions do breakdown their long term quota obligation into interim milestones. Hawaii used interim milestones for its RPS:

- 10% of its net electricity sales by December 31, 2010;
- 15% of its net electricity sales by December 31, 2015;
- 25% of its net electricity sales by December 31, 2020; and,
- 40% of its net electricity sales by December 31, 2030.

California, for example, recently increased its RPS from 33% by 2020 to 50% by 2030. With its updated target, it recently announced its interim milestones:

- 20% of retail sales by December 31, 2013;
- 25% of retail sales by December 31, 2016;
- 33% of retail sales by December 31, 2020;
- 40% of retail sales by December 31, 2024;
- 45% of retail sales by December 31, 2027; and
- 50% of retail sales by December 31, 2030.

New York, which has recently announced its updated target to also achieve 50% by 2030, is also contemplating interim milestones having proposed a triennial review process through 2030.

9.3 Financial incentives

With respect to the US Federal fiscal incentives identified, could you provide a summary of what they are, eligibility, duration, what they are applied to, etc.

US fiscal incentives	Description	Value	Term	Eligible technologies
Production Tax Credit ("PTC")	Inflation-adjusted per-kWh tax credit for electricity generated by qualified energy resources and sold by the taxpayer to an unrelated person during the taxable year	US$0.023/kWh for wind, geothermal, closed-loop biomass US$0.012/kWh for other eligible technologies	10 years	Wind, geothermal, biomass, landfill gas, municipal solid waste, qualified hydroelectric, and marine and hydrokinetic
Investment Tax Credit ("ITC")	A dollar-for-dollar reduction in the income taxes that a company claiming the credit would otherwise pay the federal government. The ITC is based on the amount of investment in qualifying property.	30% for solar, fuel cells, small wind 10% for geothermal, microturbines and CHP	One-time credit	Solar, fuel cells, small wind, geothermal, microturbines, CHP

US fiscal incentives	Description	Value	Term	Eligible technologies
Modified Accelerated Cost Recovery System ("MACRS")	Provides an accelerated depreciation schedule for qualifying renewable technologies	5 to 7 years depending on the technology	N/A	Solar PV and thermal; Geothermal; Wind; Biomass; Municipal Solid Waste; CHP; Fuel Cells; Landfill Gas; Tidal; Wave; Ocean Thermal; Anaerobic Digestion; Microturbines
Loan and loan guarantee programs	Low cost financing or loan guarantees offered to specific early stage clean energy technologies	Varies; current solicitation seeking up to $4 billion in loan guarantees	Vary on case by case basis	Vary based on solicitations but generally early commercialization

Has any jurisdiction used a 'price discovery' mechanism to find the incentive level?

We do not know of any jurisdictions that have used a "price discovery" mechanism for fiscal incentives, however, there are several examples of such an approach being used to determine the incentive level for feed in tariffs in this way. China started using auctions in 2003 to introduce a more market-based approach to its FIT program. Now the FIT levels for several renewable technologies, including offshore and onshore wind, and solar are developed using an auction mechanism. Italy uses a slightly different approach, introduced in 2013 in an effort to reduce its growing FIT costs. It establishes a capacity cap on each technology and has developers bid in a descending auction to offer the lowest price as compared to the existing FIT to be able to develop their projects. More consistent prices and price decreases have generally been observed from using these price discovery mechanisms.[100]

Similarly, as discussed in the main body of this report, there are also some examples of price discovery mechanisms in centralized procurement processes, notably in the UK's CfD.

[100] IRENA. "Renewable Energy Auctions: A Guide to Design 2." 2015.

9.4 Feed In Tariff Programs

Was there any competitive element to how price was set for the German FIT 2 program?

The new Renewable Energy Resources Act 2014 (frequently referred to by its German acronym as "EEG 2014") updated the FIT program, which had generally been viewed as too generous. Several components were introduced to the FIT program:

- Generators of renewable energy are required to sell directly into the wholesale market, receiving the market price for electricity. They will then receive a "market premium," to total the FiT amount. Until the end of 2016, market premium for generators are to be determined based on the pre-set FiT tariffs.

- At the same time, the tariffs for new renewable projects will be subject to annual, quarterly, or monthly decreases. These decreases will occur automatically and can be accelerated if the amount of new generation capacity in a given technology exceeds the targeted amount set by the government.

Appendix E

Renewable Electricity Program

1. Tell us about yourself

a. Please provide your name, contact information, the organization you represent, and your interest in responding to the AESO's questionnaire (e.g., developer, investor, association, other, etc.).

b. If you are a developer, please indicate:

   1) the type of renewable electricity generation project that you may be interested in pursuing;
   2) the anticipated size of such project;
   3) your preferred region within the Province for siting your facility;
   4) whether you have invested in electricity generation in Alberta in the past, and summary details with respect to such investment; and
   5) your organization's current renewable electricity generation portfolio (type and MW) and the applicable location/jurisdiction of the projects within such portfolio.

c. Please identify whether you currently have renewable projects in the AESO connection queue and if so, the relevant stage.

d. If you are not a developer, please indicate your interest.

2. Tell us about your view on investing in electricity generation in Alberta

a. What do you anticipate might be barriers to investing in renewable electricity generation in Alberta? What are your recommended proposals to address or mitigate against such barriers?

b. What do you view as key risks associated with investing in renewable electricity generation projects in Alberta?

c. What key information is necessary for you to have prior to making a decision to invest in Alberta?

d. Do you anticipate investing in non-renewable electricity generation in Alberta? What would influence your decision to invest in non-renewable generation, renewable generation, or both?

3. Tell us about your plans if you were to invest in renewable electricity generation in Alberta

a. Describe the key activities and timelines associated with the development, regulatory approval and construction of your anticipated renewable electricity generation project(s) (i.e. from inception through to energization).

b. Assuming your project is selected by the AESO prior to the end of Q1 2017, do you foresee any material barriers to energizing your project prior to the end of 2018?

2500, 330-5th Avenue SW, Calgary, Alberta T2P 0L4 Phone: 403-539-2450 Fax: 403-539-2949
www.aeso.ca www.poweringalberta.com

4. What is your view with respect to technological advances that may be on the horizon for the renewable sources of generation that are of interest to you.

5. General comments

a. Based on the description of the Renewable Electricity Program described on the AESO website, please provide your general comments and feedback.

Please save the completed questionnaire and email to rep@aeso.ca

Appendix F

JCRA
JCRA Financial LLC
Financial Risk Consultants

William Kloehn
CEO
One Penn Plaza, Suite 1423
New York, NY 10119

Direct Phone: 1 646 640 3619
Fax: 1 646 224 8443
Email: william.kloehn@jcrafinancial.com

May 19, 2016

Elizabeth Moore
Alberta Electric System Operator
2500, 330 5th Avenue SW
Calgary AB T2P 0L4
Canada

Dear Elizabeth,

Thank you for the recent inquiry on the status of the financing markets and the implications for Alberta's energy-only electricity market and its plans to introduce significant renewable electricity generation. We understand that the Alberta Electric System Operator ("AESO") has seen uncertainty surrounding electricity price forecasts and is questioning whether this uncertainty has dampened developer interest in the AESO's market.

Furthermore, we understand that the AESO is keen to understand the extent to which this dampened interest is caused by increased price uncertainty or whether other factors, such as changes to the underlying financing markets, have had an impact. Specifically, the AESO has asked us to provide answers to the following questions:

1. Do you think that the price uncertainty observed in Alberta's energy-only market today would dissuade new investment and/or present challenges when it comes to financing new capital expenditure (both in terms of availability of finance and cost)?

2. Generally speaking, when it comes to raising finance for projects that carry merchant price risk, do you think that finance markets today are more or less conservative than in previous years (in terms of both project and corporate finance)? If so, do you consider this to be a fundamental shift in the risk appetite of finance markets or rather the result of typical market cycles?

3. In previous years, projects carrying merchant price risk have been readily financeable in Alberta using corporate finance. Do you think that those same projects would be equally financeable today if the increased price uncertainty evident in the market was absent?

In answering the above questions, we understand that the AESO has not asked us to study the Alberta market or the details of the Alberta's plans to introduce renewable electricity. Such a review would be needed to provide a more complete answer. Instead, we have focused on the status of the financing markets and whether that status of the financing markets alone could have created dampened developer interest.

The first question addresses whether price uncertainty would dissuade new investment or present challenges when financing new capital expenditure. Price uncertainty is an important issue when developers look to finance their projects. Without any price certainty, projects will have a difficulty in raising debt finance. This situation would create a scenario where projects would likely only be all-equity financed, thereby creating, at the very least, a very expensive capital structure and potentially other challenges.

Following the recent financial crisis, many projects were financed with power purchase agreements. These provided the market with comfort regarding both volume and price. There were numerous projects that were completed in both Canada (eg. Ontario FIT program) and the United States (eg. California and the Alta Wind projects).

As the financial markets became more healthy after the crisis, investors and the banks started taking more risks and developers were able to finance projects without long dated power purchase agreements. Price uncertainty remained a key risk, but many developers found that they are able to finance projects with revenue hedges. Banks provided these hedges with tenors of 5 to 7 years in the United States. Recently, we are aware that Capital Power's Bloom Wind Farm in Kansas closed a financing with a 10 year proxy revenue swap hedge to provide stability regarding the project's revenue for a low base amount of power. The hedge provided sufficient certainty to permit the debt financing to close. The hedge was provided in a partnership through Nephila Capital and Allianz and the project is financed by Capital Power on balance sheet using corporate debt and cash flow from operations. The project is not secured by any power purchase agreement. Allianz is rumored to have closed on other financings in the US recently.

As it relates to the second question, our view would be that the financial markets have been willing to take on greater financial risk than in the years immediately following the financial crisis. Immediately after the financial crisis, the most viable projects were those that had power purchase agreements to provide revenue stability following construction completion. As the economies improved, debt investors have taken on increasing risk. In project finance transactions, credit spreads on the projects initially financed in the bank market have been refinanced with lower credit spreads ranging from 150 basis points to 175 basis points. This phenomenon has been evident in both Canada as well as the United States and would be expected given this stage of the economic recovery.

In order to understand the condition of the corporate finance market, we examined the bond market in the Canadian market from 2009 through 2015. In selecting the relevant sample set, we specifically excluded issuances related to the following sectors:

- Governmental issuances
- PPP/availability payment backed bond issues
- Bond issuances reliant on power purchase agreements for revenue and/or repayment
- Financial institution issuances
- Issuances deemed to be backed by relatively stable businesses

We specifically attempted to include issuances in the energy sector where the above factors were not evident. The outcome produced the following results:

	2009	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**
Number of Issuances	31	34	40	61	59	56	42
Maximum Size	1000 MM	800 MM	1450 MM	1100 MM	1225 MM	1530 MM	2185 MM
Average Size	520 MM	450 MM	475 MM	625 MM	609 MM	643 MM	728 MM

In our view, we believe that the corporate financing market was very active the last three years for financings that support businesses with price/volume variability.

In the US, we have also seen that institutional investors have also taken greater risk. Last year, the Indiana Toll Road, a toll road that is subject to both price and volume variability, was purchased by IFM out of bankruptcy. The purchase price for the toll road was $5.72 billion, a price that was larger than the original $3.8 billion purchase price in 2006. While the leverage in the capital structure was more conservative, the fact that the acquisition was completed using bank financing followed by a capital markets takeout is proof that the corporate finance market is willing to take risk. Finally, it should be noted that IFM was able to reduce the bank financing amount due to institutional investor demand that was willing to commit to the financing at a fixed rate prior to the completion of the acquisition conditions precedent.

In the first quarter of 2016, another financing was completed for the acquisition of the Chicago Skyway, another toll road that is subject to both price and demand variability, by Ontario Teachers, OMERS, and Canada Pension Plan Investment Board.

And on May 5, 2016, we understand that CalPERS agreed to purchase a 10% stake in the Indiana Toll Road, thereby indicating that the secondary equity market is willing to take risk.

Overall, we believe that the financing market is less conservative than what we have seen coming out of the financial markets. Immediately after the financial crisis, the markets primarily financed projects with a true power purchase agreement (PPA). Now they have moved gradually to accept a small amount of risk and see revenue hedges. When they accept revenue hedges, there is greater risk because the financial entity providing the hedge could default, thereby leaving the project without a hedge (especially given the limited number of hedge providers) or one that is very expensive. Furthermore, if the project goes bankrupt, then the lenders must also share the remaining assets. Even with the revenue hedges, some of the projects are rated relatively lowly (ie. B or BB category), thereby highlighting the risk. Overall, capital structures tend to have less leverage than prior to the financial crisis; but investors are willing to take more risk structurally. We would expect this to be a normal evolution in the financing markets associated with this stage of the recovery. We would also expect that the market may never get to the leverage that existed prior to the financial crisis and all financial institutions have permanently increased risk awareness. If anything, this latter point may be considered a fundamental shift.

As for the future, the energy market is very different than the past when there were more limited sources of energy. The impacts of the financial crisis and increasing regulatory capital requirements are here to stay even though there will be cycles. As a result, I think that the market will continue to focus on the revenue side of the equation and look for certainty. There might be some parts that take on some merchant risk, but the merchant part will be heavily discounted but all parties. If there is too much merchant risk, then it won't be a capital structure question but even the developers will shy away from the projects.

As it relates to the third question, the financial markets have gone through a fair amount of volatility. Initially, 2015 represented a year of significant investor demand. This was not evident in the figures above due to the exclusion of the record setting C$2.5 billion PPP bond issuance. During the mid to late summer of 2015, the increased supply of bond issuance combined with global risk factors (eg. Greek governmental issues, Puerto Rican debt difficulties, slower Chinese growth, etc.) caused Canadian bond spreads to increase approximately 40 basis points. The demand tapered off in the last quarter of 2015. While the first quarter of 2016 did not exhibit significant investor demand, we have begun to see much greater demand in the second quarter of 2016. This greater demand has been accompanied with declining credit spreads. This suggests that the developers and investors are open to investing in projects.

In order to determine whether developers and investors would be willing to invest in Alberta's renewable projects, the confidentiality of our work prevented us from interviewing and talking to people outside the project team. Therefore, we chose to examine the Texas electricity market. We picked Texas for the following reasons:

- The Texas market has significant size and is also an energy-only market.
- Five to six years ago, ERCOT procured a number of energy projects on the basis that it forecasted that the Texas grid would face potential shortages well through 2016 during times of peak demand. However, since that point in time, natural gas prices in Texas have dropped significantly and there has been a significant production of wind and solar electricity production. Consequently, the abundance of new power generation has depressed the wholesale power market.

Therefore, the ERCOT market is one that has similarities with Alberta and the situation within ERCOT can provide important guidance as to the ability to finance energy projects.

The first example is the current status of Panda Power's projects in Texas. Five to six years ago, Panda Power bid for and won the right to build a number of projects. In preparing their bids, they claimed that they relied on ERCOT's forecast in terms of volume and price for which it would be able to sell power to the grid. The abundance of power at lower price points has significantly impacted Panda so much that it has decided to sue ERCOT claiming that its projections were false and misleading and that, as a result, Panda will not be able to turn a profit for its two plants in Temple and one Sherman. Whether the projections were false or misleading is not the point, but clearly market forces have changed so much that the previous forecasts clearly do not reflect reality.

Recently, we have learned that Panda Power is looking to refinance its Sherman plant which sells power on a merchant basis. The original financing was done in 2012 with institutional Term Loan B investors in the US and the project was rated B+. Due to the abundance of power at lower prices than forecast, the resulting debt coverage ratio had dropped to less than 1 times, thereby indicating that the project's cash flows can not meet its interest and principal debt repayments. In January 2016, Standard & Poors downgraded the debt from B+ to B- and warned of further potential downgrading. If the refinancing does close, it is unlikely that the banks will play in the refinancing and that the most likely source of financing will come from distressed credit funds.

Given the situation above, we believe that Texas will have to change its market strategy in order to get more developers and investors to build more capacity for growth and plant retirements. On May 17, 2016, a subsidiary of the Chinese turbine manufacturer, Goldwind, announced that it is buying the 160MW Rattlesnake merchant wind project from RES Americas. Goldwind is using bridge financing, a construction loan, and tax equity to finance the project that is being arranged on the basis that a long term fixed price hedge with ERCOT will be agreed. We would expect that Texas will have to restructure its energy only market, as have other electricity markets in the US, to provide more revenue stability.

Although this project is not in the ERCOT market, it does reflect the developer and investor focus on revenue stability. In June 2015, Con Ed Development agreed to purchase the 94MW Campbell County wind farm in South Dakota from the developers, Fagen Inc and Dakota Plains Energy. Con Ed Development is the unregulated arm of Consolidated Edison and was formed in 1997 to invest in renewable energy and gas assets as a part of its responsibility to environmental stewardship. The financing of the acquisition was not based on tax equity, which is one of the financing structures that can take longer close. The project became operational in December 2015. However, the acquisition only closed on May 12, 2016 when the negotiation of a 30 year power purchase agreement and amendment of guaranteed volumes with the Basin Electric Power Cooperative along with other conditions precedent to the acquisition were met.

Therefore, we believe that the debt capital markets would be receptive to properly structured projects that you refer to if the increased price uncertainty in the market was absent.

The above represents addresses is our view regarding the financial markets relative to your questions taking into consideration both the time and information that we have had our disposal to address your questions. We would be happy to discuss the above with you at your convenience to answer any questions that you may have and/or to provide additional details. As time passes, we would expect that the status of the financial markets will continue to evolve and would be willing to update our analysis accordingly.

Regards,

William Kloehn

Alberta Electric System Operator
2500, 330-5th Avenue SW
Calgary, AB T2P 0L4
Phone: 403-539-2450
Fax: 403-539-2949
www.aeso.ca
www.poweringalberta.ca
@theaeso

05/16