Plugging In

Opportunities to procure renewable energy for non-utility companies and institutions in Alberta

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March 2018

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The Pembina Institute is a national non-partisan think tank that advocates for strong, effective policies to support Canada's clean energy transition. We employ multi-faceted and highly collaborative approaches to change. Producing credible, evidence-based research and analysis, we consult directly with organizations to design and implement clean energy solutions, and convene diverse sets of stakeholders to identify and move toward common solutions. Find out more at www.pembina.org.

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Rocky Mountain Institute (RMI)—an independent nonprofit founded in 1982—transforms global energy use to create a clean, prosperous, and secure low-carbon future. It engages businesses, communities, institutions, and entrepreneurs to accelerate the adoption of market-based solutions that cost-effectively shift from fossil fuels to efficiency and renewables. RMI has offices in Basalt and Boulder, Colorado; New York City; Washington, D.C.; and Beijing.

Rocky Mountain Institute's Business Renewables Center (BRC) is a member-based platform that streamlines and accelerates corporate purchasing of off-site, large-scale wind and solar energy. With over 200 members, including major corporations, leading renewable energy project developers, and transaction intermediaries, the BRC embodies the know-how of the industry. Today, BRC members account for over 8 gigawatts of renewable energy, and more than 93% of corporate renewables deals to date have included a BRC member. With a goal to help corporations procure 60 gigawatts of renewable energy by 2030, the BRC is at the leading edge of the fastest-growing sector of renewable energy procurement.

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Calgary Economic Development is an opportunity-maker, helping to spark and fuel Calgary's growth. Our job is to connect people with resources that can help them grow their careers or businesses, thrive in new locations or markets, and feel at home in our community. We offer a wealth of information to help everyone succeed and we tirelessly promote Calgary, in Canada and around the world. We're exhilarated about our role in shaping and sharing Calgary's story and we're proud to be part of the energy in the green economy. For more information, please visit our website at calgaryeconomicdevelopment.com and follow us on Twitter @calgaryeconomic.

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About this work

Calgary Economic Development, The Pembina Institute, and Rocky Mountain Institute are conducting a study on Alberta's electricity market to assess the potential for companies and public institutions outside the utility sector to buy electricity directly from renewable energy developers. This guide is one output of the study.

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Executive summary

The precipitous fall in renewable energy costs has arrived at a time when voluntary sustainability targets are multiplying and carbon compliance obligations have increased in Canada. Indeed, globally 122 companies have established 100% renewable energy targets, and many other entities have similarly strong commitments. After exhausting energy efficiency and on-site opportunities, these companies and other non-utility buyers typically seek to procure energy at large scale, and look toward off-site projects. There is now a strong economic case for using large-scale renewable energy projects as a tool to meet a range of targets and goals.

The opportunity for all actors

"Non-utility procurement" refers to the acquisition of renewable energy and associated environmental attributes by corporate entities and other non-utility buyers (universities, government agencies, etc.). Non-utility procurement can help buyers meet sustainability goals and objectives or carbon compliance requirements while providing long-term electricity price security. Alberta, with a deregulated wholesale electricity market and a carbon compliance requirement, is the logical hub for Canadian non-utility procurement, and offers buyers the opportunity to meet goals and objectives in the Canadian context.

Alberta's electricity market

Alberta has a fully deregulated electricity market consisting of electricity generators, retailers and customers, as well as regulatory agencies such as the Alberta Electric System Operator (AESO). Any qualified electricity generator can make a competitive offer to sell its electricity into the wholesale power pool, any qualified retailer can buy and sell electricity from the wholesale market, and customers can choose their preferred retailer. Alberta's deregulated market provides market participants with the flexibility to enter into agreements with one another, allowing non-utility buyers to sign procurement contracts with generators.

Alberta's electricity grid has historically consisted primarily of large-scale, centralized coal and gas electricity generating stations operated by independent power producers (IPPs) and large municipally owned utilities. In total, Alberta has approximately 235 electricity generating stations operated by 200 IPPs. The wholesale power pool is administered by the AESO.

Renewable procurement for non-utility buyers

How does a non-utility purchase renewable electricity? The answer is an agreed-upon system of tracking the renewable attribute—essentially, the mechanism for capturing the environmental benefits of producing renewable electricity (e.g., reduction in CO_2 or other pollutants), or tracking the "renewableness" of the electricity.

Renewable attributes—or environmental attributes (EAs)—are the commodity purchased when we speak of purchasing renewables. Non-utility buyers have three options when considering a renewable energy purchase Canada: (1) procure from an on-site project, (2) procure from an off-site project, or (3) invest directly into a project. In all cases the EAs must be retained and retired by the purchaser in order to claim the use of the renewable energy (they can not be sold or used to meet other environmental obligations).

In terms of total renewable generation volume across the United States, one of the most common structures is off-site procurement via a virtual power purchase agreement (VPPA). The structure and rules for the purchase differ between systems/jurisdictions, but generally a VPPA between a renewable energy project and a buyer provides that all EAs flow to the buyer. As long as the EAs are purchased through the contract, retained, and retired by the buyer, the buyer is able to claim the use of the renewable energy.

Off-site environmental attribute purchases (for example, through a VPPA) do not disrupt the existing relationship between the purchaser and their utility provider, which still delivers electricity.

Off-site transactions as a proven route to reach goals

Off-site transactions allow a buyer to procure at scale and meet goals/objectives—a single transaction can result in material progress toward a target. To date, 52 corporate and other non-utility buyers in the U.S. and Mexico have entered into such VPPAs, and procured EAs directly from off-site, utility-scale renewable plants. While this is a relatively recent phenomenon—in the years before 2013, only a few companies had executed transactions—it has strong momentum. The market grew substantially in 2013, not only in total volume but also with the entrance of first-time buyers. While the majority of deals in the early years were done by the technology sector, the group of buyer companies has now spread to other sectors. Notably, 2017 saw the rise of the consumer goods sector. We expect this trend to continue and proliferate into new sectors.

Conversations with experienced buyers highlight that the group use their established goals and targets to translate organizational objectives and inform the appropriate mix of different procurement options to meet the goals, plus the priorities/concerns for transactions. Understanding buyer priorities/concerns will inform the buyer's stance on specific risks/opportunities within a transaction—an important element of an off-site transaction, which can introduce risks or opportunities many buyers have previously not considered.

Clear roadmap of lessons learned

From the wisdom of many experienced buyers of off-site energy, the Business Renewables Center has developed a buyers' roadmap, which is designed to guide buyers through the transaction process and to inform project developers and service providers how buyers transact, and support the provision of high quality products and services. This roadmap is outlined in the final chapter of this report.

Introduction

The Pembina Institute and Rocky Mountain Institute, with Calgary Economic Development, have developed this document to inform stakeholders regarding the opportunity for long-term non-utility procurement of renewable energy in Alberta. This document is intended for a primary audience of non-utility buyers.

It is meant to be read as a cohesive document that outlines the considerations of non-utility procurement. This document starts with foundational content and builds quickly to more advanced information relevant to experienced buyers, developers, and service providers.

Opportunity statement

"Non-utility procurement" refers to the acquisition of renewable energy and associated attributes by corporate entities and other non-utility buyers (universities, government agencies, etc.). Non-utility procurement can help buyers meet sustainability goals and objectives or carbon compliance requirements.

Alberta, with a deregulated wholesale electricity market and a carbon compliance requirement, is the logical hub for Canadian non-utility procurement, and offers buyers the opportunity to meet goals and objectives in the Canadian context.

Fundamentals of renewable energy procurement

Grid and attribute fundamentals

Alberta's electricity market

In a fully deregulated electricity system like Alberta's, independent power producers (IPPs) make competitive offers to sell their electricity into the wholesale power pool that is managed by an independent system operator (ISO) or regional transmission operator (RTO). The price the IPP receives is determined by the intersection of supply and demand on an hourly basis. Electricity retailers then purchase bulk electricity from the wholesale market through a mix of forward market and real time purchases based on projected electricity demand from their customers. These retailers repackage the electricity into appropriate retail "bundles" and sell it to end-use customers. Figure 1 illustrates this market.

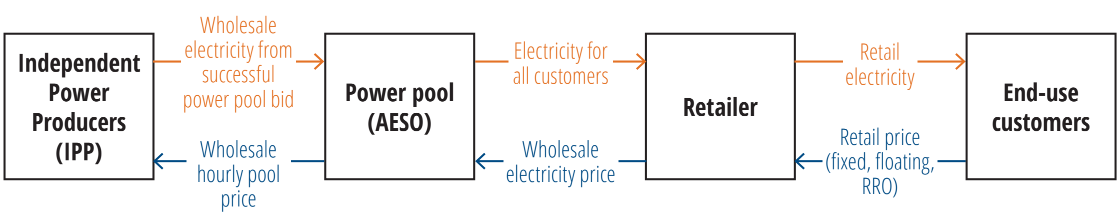

Figure 1. Stakeholders in the electricity market

The price that customers pay for electricity depends on their agreement with their retailer. Customers can also choose to act as a self-retailer to purchase electricity directly from the wholesale market, but typically only large electricity users gain the scale of benefit compared to the added complexity of self retail.

On the grid, electricity from the centralized generating stations first flows over long-distance transmission lines, which carry the electricity to regional distribution grids and ultimately to residential, commercial, and industrial customers (Figure 2). The amount of electricity consumed by end-use customers is measured on an electrical meter at their facilities.

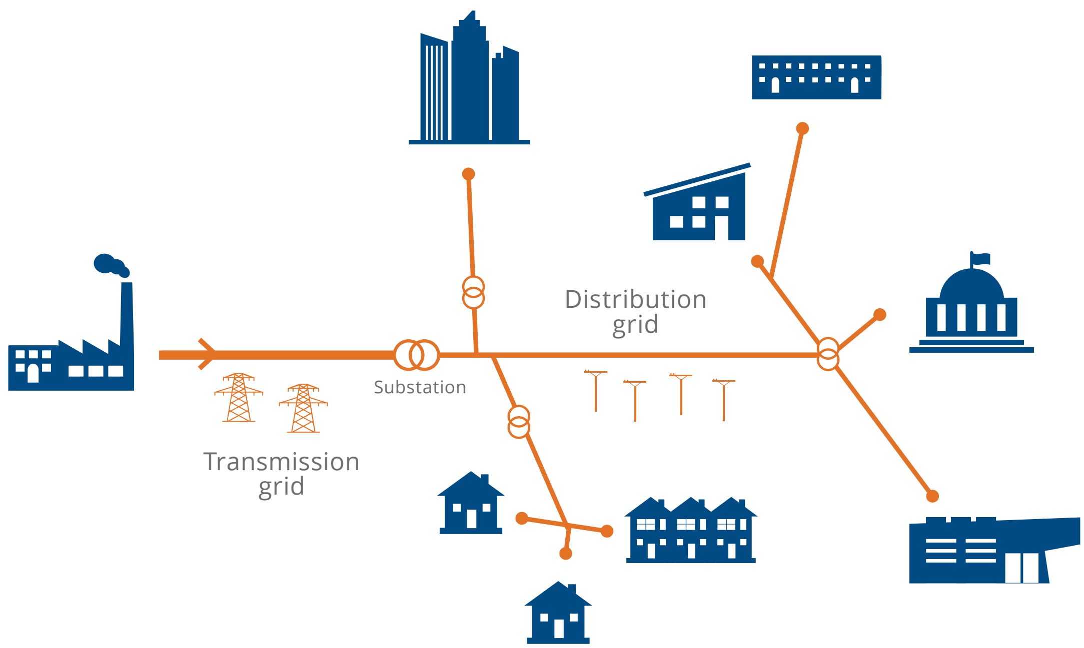

Figure 2. Electricity grid

Electron flow and renewable attributes

A few key facts are important to keep in mind when considering procurement options:

- Electricity is a flow of electrons.
- There is no difference between "green" electrons (such as those generated by a renewable facility) and "brown" electrons (such as those generated by a fossil fuel-based facility). There are only electrons, and they are interchangeable.
- Electrons flow on the grid according to certain laws of physics. We cannot order one set of electrons to flow in one direction and another set of electrons to flow in another direction.

It may be helpful to compare the flow of electrons to the flow of water in a branching stream. If one adds a few drops of green dye upstream, one cannot control whether the green dye follows the left branch or the right. Similarly, when one adds electricity from a renewable energy project to the grid, one cannot direct those electrons to flow to a specific building. How then does one purchase renewable electricity? The answer is an agreed-upon system of tracking the renewable attribute—essentially, the mechanism for capturing the environmental benefits of producing electricity (e.g., reduction in CO_2 or other pollutants), or tracking the "renewableness" of the electricity.

Under the most commonly used structure, purchasing renewables actually means purchasing renewable attributes (or environmental attributes (EAs)). The structure and rules for the purchase work differently in different systems/jurisdictions, but generally a contract stipulates that all of the environmental attributes of a renewable energy project flow to the buyer in the contract. As long as the EAs are purchased through the contract, retained, and retired by the buyer, the buyer is able to claim the use of the renewable energy. The ownership and treatment of the actual electrons can be managed in different ways as described below.

Globally there are various systems and registries to track renewable energy attributes, such as renewable energy certificates (REC) in the U.S., which are used in the compliance/mandatory market as well as the voluntary market. (See the sidebar below for a basic overview of RECs.) In Europe, guarantees of origin (GOs) label energy from renewables. In Alberta, environmental attributes can be converted and tracked in a public registry as offsets where renewable energy projects are used to meet carbon compliance requirements.

U.S. REC basics

One megawatt-hour of electricity generated by a renewable energy plant also generates one Renewable Energy Certificate (REC). The owner of that plant may sell ownership of the REC to a utility or any other buyer that is interested in claiming credit for the renewableness of the electricity it consumes. Once this credit is claimed (or 'retired'), it may not be transferred again. This way, only one entity may receive credit for using the renewable energy.

Additionality

One of the key characteristics when considering the purchase of EAs is additionality.[1] Additionality is a confusing term, in part because it has no broadly accepted definition in this space. However, the underlying concept might be summarized by the question: To what degree does my EA procurement result in more renewables in the electricity grid?

Different observers—companies, shareholders, customers, and other stakeholders—may view some procurement options as seeming somehow more or less legitimate than others. Part of this perception can be due to a lack of familiarity with what renewable

[1] The concept of additionality has been debated for over 20 years, and this report does not seek to join that debate. For more information, see Mary Sotos, *GHG Protocol Scope 2 Guidance* (World Resources Institute, 2015). http://www.ghgprotocol.org/sites/default/files/ghgp/standards/Scope%202%20Guidance_Final_0.pdf

electricity and renewable attributes actually are, but beyond that it is reasonable for some of these options to appear more credible. Key measures supporting the credibility of additionality claims can include the length of term of the contractual commitment, the age of the project, and contribution of funds for project development.

Often, EAs with a lower level of additionality may be viewed as lower-quality EAs, or less impactful. Depending on their goals, different stakeholders will seek out different quality EAs.

Renewable procurement for non-utility buyers

In procuring renewables, the buyer must retire EAs to claim the use of renewable energy. In fact, the buyer is in many cases procuring only the EAs; the renewable energy itself may be supplied to the buyer or it may be sold elsewhere, depending on the option used.

Non-utility buyers have three options when purchasing renewable energy in Canada:

1. procure from an on-site project
2. procure from an off-site project
3. invest directly into a project.

These options contain suboptions, outlined below.

Table 1. Options for renewable energy purchase

On-site options	Off-site options	Investment
On-site power purchase agreement On-site lease	Virtual power purchase agreement Direct/physical power purchase agreement Utility-based offering	Project investment, on- or off-site

On-site options

On-site projects are physically located on the buyer's site, and may also be described as *behind the meter* or *behind the fence*.

On-site renewable energy projects can include (but are not limited to) ground source heat pumps, rooftop solar, ground-mount solar, wind power, or biogas-fired combined heat and power systems.

From the perspective of the utility, on-site projects sit on the customer's side of the electricity meter, and any electricity produced and used directly by the buyer reduces the amount of electricity purchased from the utility. This means that the utility does not have direct insight into how much electricity is produced by the local system, as it sees only the amount of electricity that flows from the grid through the meter. This amount would be equal to the consumption of the building net of any generation behind the meter.

The economic attractiveness of on-site projects depends on physical factors (e.g., available space for an on-site solar photovoltaic [PV] system), financial and deal-structure factors (e.g., credit rating of the buyer, owning vs. leasing the system), and regulatory factors such as the existence of a net-metering or net-billing policy.[2]

Two common types of on-site project procurement contracts are on-site PPAs and on-site leases. Both can allow the buyer to obtain the EAs flowing from the project's production.

On-site power purchase agreement

An on-site power purchase agreement is typically a long-term contract in which the buyer agrees to pay a fixed or escalating price per unit of energy generated. The buyer does not own the generation equipment, even though the assets are located at the buyer's facilities. A buyer would usually negotiate to obtain the EAs with the electricity flowing from the project.

On-site lease

Very similar to an on-site PPA, customers lease the energy equipment and receive the electricity it generates.

[2] For more information on net billing and net metering, see Barend Dronkers and Sara Hastings-Simon, *Making electricity billing fair: How Alberta's billing system disadvantages small solar generators* (Pembina Institute, 2017). http://www.pembina.org/pub/making-electricity-billing-fair

Off-site options

Off-site projects are located away from the buyer's load center. Off-site renewable energy projects can utilize any type of renewable technology, such as wind, solar PV, hydro, or biomass.

Off-site projects must be connected to the grid. In a deregulated market like Alberta's, these projects bid into the market and sell electricity when dispatched by the relevant ISO or RTO (in Alberta the AESO). Off-site projects do not interrupt the buyer's relationship with their utility.

Three common types of off-site procurement contracts are VPPAs, direct/physical off-site power purchase agreements, and utility-based offerings/green tariffs. All can allow the buyer to obtain the EAs flowing from a project's production.

2.1 Virtual power purchase agreement (VPPA)

In terms of deal volume, the VPPA has been the primary structure employed to procure renewable attributes from off-site projects. Also known as a financial PPA or a contract for differences, the VPPA does not transfer legal title to electricity to the buyer. The project (or a third party) retains ownership and sells the electricity at the market price and the buyer receives the EAs from the project.

The buyer pays a fixed unit price to the developer under the contract and receives the floating market price the electricity is sold at. The buyer is backstopping the price that the project receives for its electricity on the market: if the market price is lower than the fixed contract price, the buyer makes up the difference, but if the market price is higher, the buyer receives the difference. Importantly, the buyer still purchases electricity for their own use from their regular utility at the market price. See Figure 3 for details.

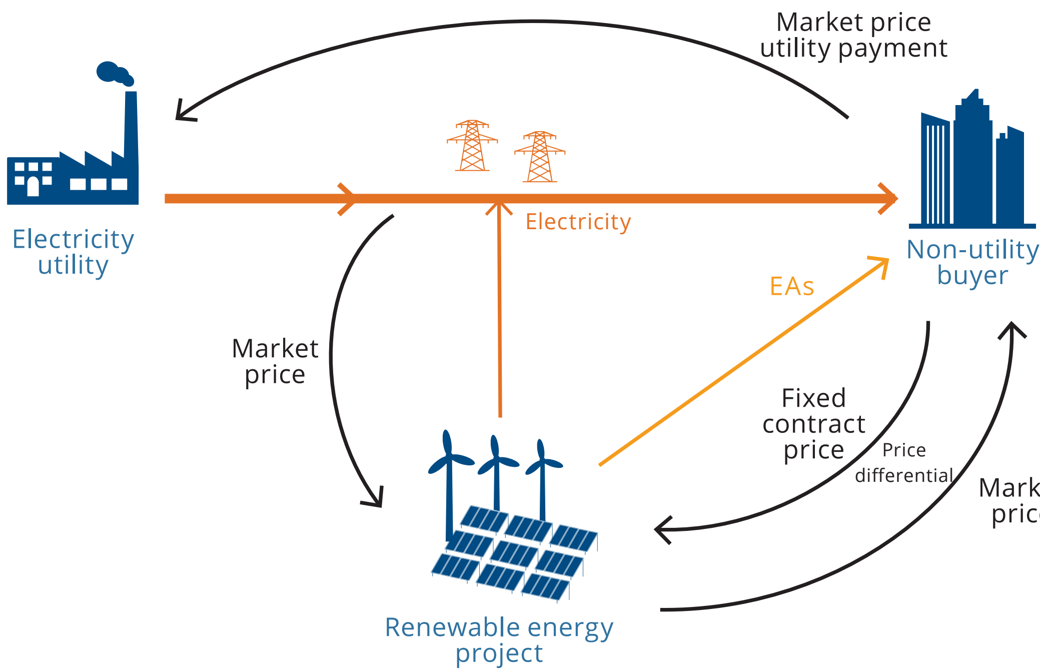

Figure 3. Structure of the VPPA transaction

Balancing risk and reward

The record-breaking rates announced in December 2017 from new renewable energy projects in Alberta highlight how competitive the sector has become, and reinforced the economic case for using off-site projects to meet sustainability goals.

The VPPA is a tool to procure EAs, and meet targets/goals while capturing economies of scale. Since buyers continue to procure electricity from their suppliers at the market price, they are still exposed to the cost variability between the market price of the power they use and the power generated from the renewable energy project.

A few points are particularly important to note about this structure.

- This structure is most accessible in a deregulated wholesale market, such as Alberta's, where there are no barriers to market access.
- This structure by itself has no impact on retail purchases of electricity. The buyer continues to procure electricity for its facilities from its utility or other retail supplier. Those relationships are not affected by the VPPA.
- A buyer therefore could sign a VPPA anywhere it is legally permissible, without regard to the locations of the buyer's facilities or load centers. This means a VPPA can be effective both for buyers with a few large facilities in one region and for buyers with many small facilities spread across a wide geographical area.

Because the power plant can be located wherever the wind or solar resource is most attractive and wherever land is plentiful, it can be much larger—thus achieving economies of scale—and much more efficient (in terms of output per unit of capital cost). Furthermore, because of the large scale, it is possible for a buyer to achieve very significant progress toward its renewable energy or carbon goals with a single transaction.

2.2. Direct/physical power purchase agreement (Direct PPA)

As with a VPPA, a direct PPA is a long-term contract where a buyer agrees to pay a developer a fixed or escalating price per unit of energy generated, and acquires the associated EAs. The direct PPA includes provisions whereby the buyer takes legal title to the electricity and is responsible for managing the electricity as a commodity.

2.3. Utility and retail based offerings

Utilities/retailers may provide customers the option for delivery of renewable electricity, which may or may not be linked to specific generation assets.

For example, buyers in Alberta can sign up for a green tariff offered by utilities. Buyers continue to buy electricity from the grid, while their utility purchases and retires EAs generated by one or more renewable energy projects that are selling electricity to the grid.

Investment

3.1. Project investment, on- or off-site

In a traditional project investment, a buyer invests equity into a specific project, either on or off site. To procure the EAs generated as well, the buyer would need to include a clause in the investment agreement.

Non-utility procurement in North America

Although 52 different corporate and other non-utility buyers have procured directly off-site from utility-scale renewables plants in the U.S. and Mexico to date using these structures, this is a relatively recent phenomenon. In the years before 2013, only a few companies had executed transactions. However, the market grew substantially in 2013—not only in total volume but also with the entrance of first-time buyers.

The trend continued through the end of 2015, when a combination of an experienced buyer group and the expected expiration of the two major U.S. federal tax credits (the production tax credit (PTC) and the investment tax credit (ITC)) accelerated many deals that might otherwise have happened in 2016 into the end of 2015 (of the 3.25 GW announced in 2015, 1.72 GW—more than half of the total—were announced in Q4 that year). As a result, the first half of 2016 saw a "hangover effect," with fewer than 500 MW announced and a lower total for the year (see Figure 4). (The U.S. Congress did renew the PTC and ITC at the very end of 2015, with phase-outs over time, but the expectation of expiry had already caused the deal acceleration in 2015.)

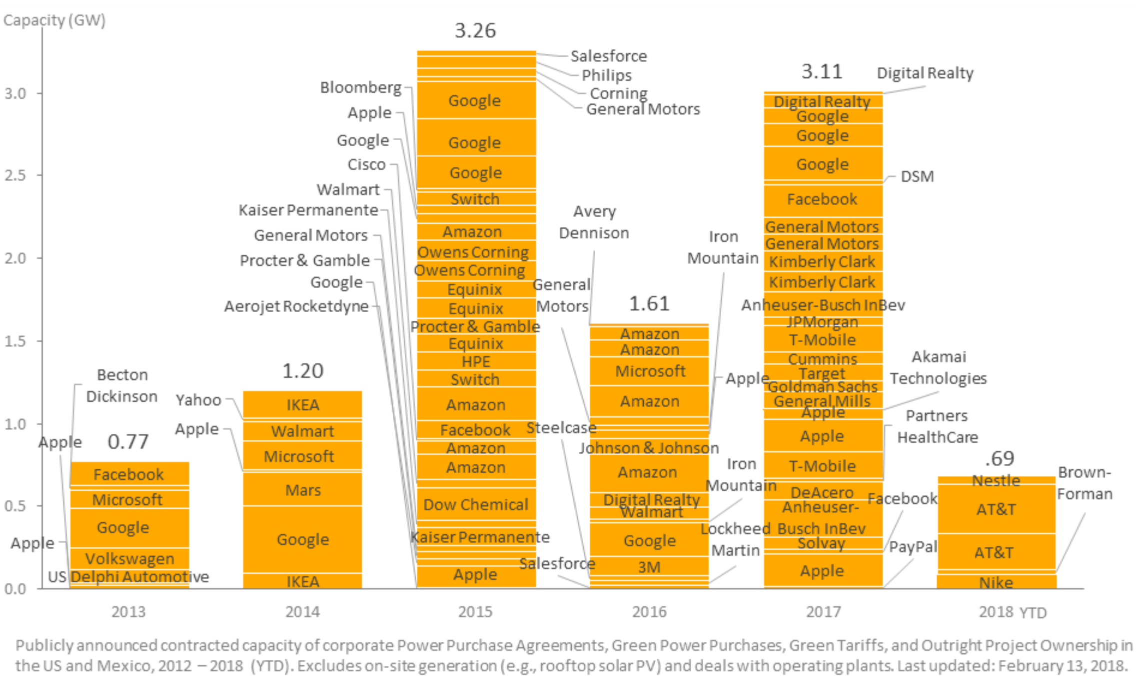

Figure 4. Corporate procurement of renewable energy

Source: Rocky Mountain Institute

The trend regained its momentum in 2017 with both repeat and first-time buyers. In fact, 13 of the 19 buyers in 2017 were new entrants into the market. The year 2018 has also gotten off to a strong start.

Procurement has spread well beyond the technology sector. While tech companies are still a strong group of buyers, 2017 saw the rise of the consumer goods sector (see Figure 5). We expect this trend to continue and proliferate into new sectors.

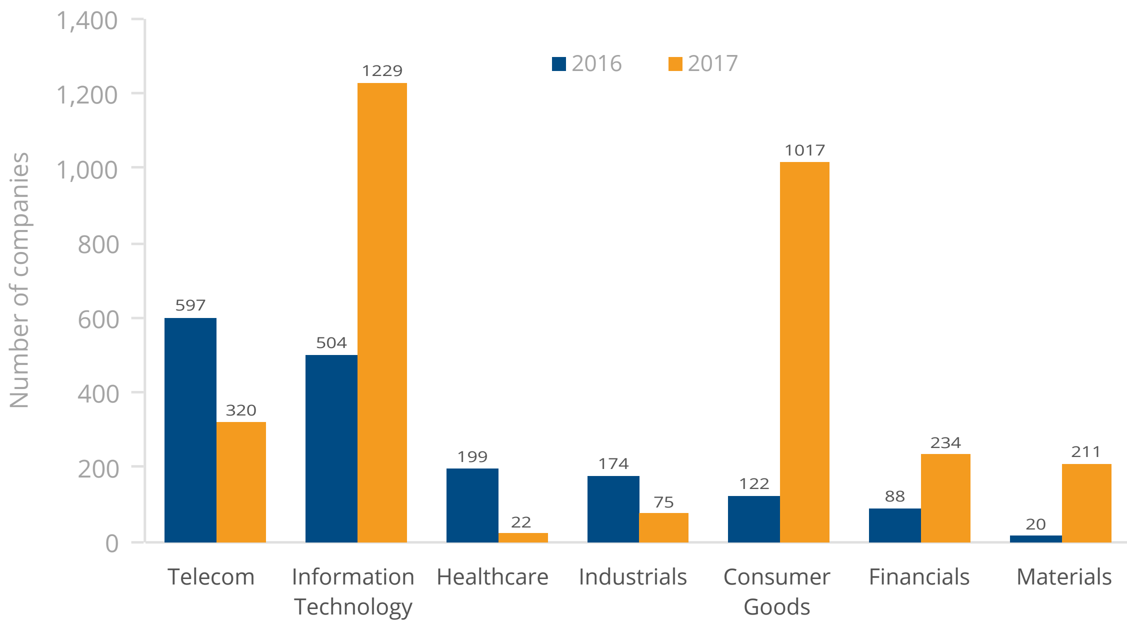

Figure 5. Sector analysis of corporate procurement of renewable energy

Data source: Rocky Mountain Institute

Buyer motivation

The majority of buyers have sought to use these transactions to meet established sustainability targets. Buyers use their established goals and targets to inform the appropriate mix of procurement options. However, taking a deeper look we see that a mix of 10 priorities and concerns are common across buyers. These are outlined below.

Figure 6. Buyer priorities and drivers

Source: Rocky Mountain Institute

Addressing off-site EA procurement market challenges

Despite strong growth over recent years and an increasing number of buyers participating, the off-site EA procurement market has experienced challenges. Over 400 market participants, including buyers, project developers and intermediaries, identified the most significant challenges, the main three of which are complexity, risk, and economics.[3]

Off-Site Challenge #1: Complexity

Buyers identified the complexity challenge as primarily relating to moving from a traditional approach to electricity procurement (one- to three-year contracts with a supplier) to a new form of contract (longer term, typically 10+ years in the U.S.).

Off-site transactions are complex and outside most companies' core businesses. Understanding the landscape and then creating internal alignment are often time-consuming efforts that can take from several months to a year or more.

Additionally, the VPPA structure means that the buyer's revenues (income received via the project owner, from electricity sold) depend on the floating wholesale market price for electricity, so a drop in wholesale market prices translates to a drop in revenues from existing PPAs. Low wholesale market prices, or expectation of falling prices, create headwinds for new companies that are considering transactions.

VPPA transactions present a significant challenge for internal deal champions seeking to educate their internal stakeholders, as many non-energy experts find the concept of an off-site EA procurement transaction difficult to comprehend, and associated risks difficult to quantify. As a result, many specialist organizations have developed specific teams to address off-site procurement complexities, and to support non-utility buyers through the process. The Business Renewables Center is an additional source of unbiased information, tools, resources, and connection to a large network of over 120 other buyers.[4]

[3] Business Renewables Center member meeting, Santa Clara, CA, September 2017.

[4] Business Renewables Center. http://www.businessrenewables.org/

Off-Site Challenge #2: Risk

The risk challenge relates to both how the buyer builds an understanding of risks, and the allocation of risks between buyer and seller.

Component #1: Understanding the risks

Off-site EA procurement, most typically through the VPPA, is a relatively new transaction for non-utility parties. And while project developers know financial models and risks intimately, buyers new to the transaction process are recognizing and resolving risks for the first time. As with Off-Site Challenge #1: Complexity, buyer-deal champions go through a steep learning curve to absorb the knowledge, synthesize it in the context of the organization, and work with stakeholders to ensure risks are appropriately allocated in the VPPA (or other) contract.

Working with buyers, developers, and service providers, the Business Renewables Center has identified four areas of risk, with numerous specific risks, as shown in Figure 7.

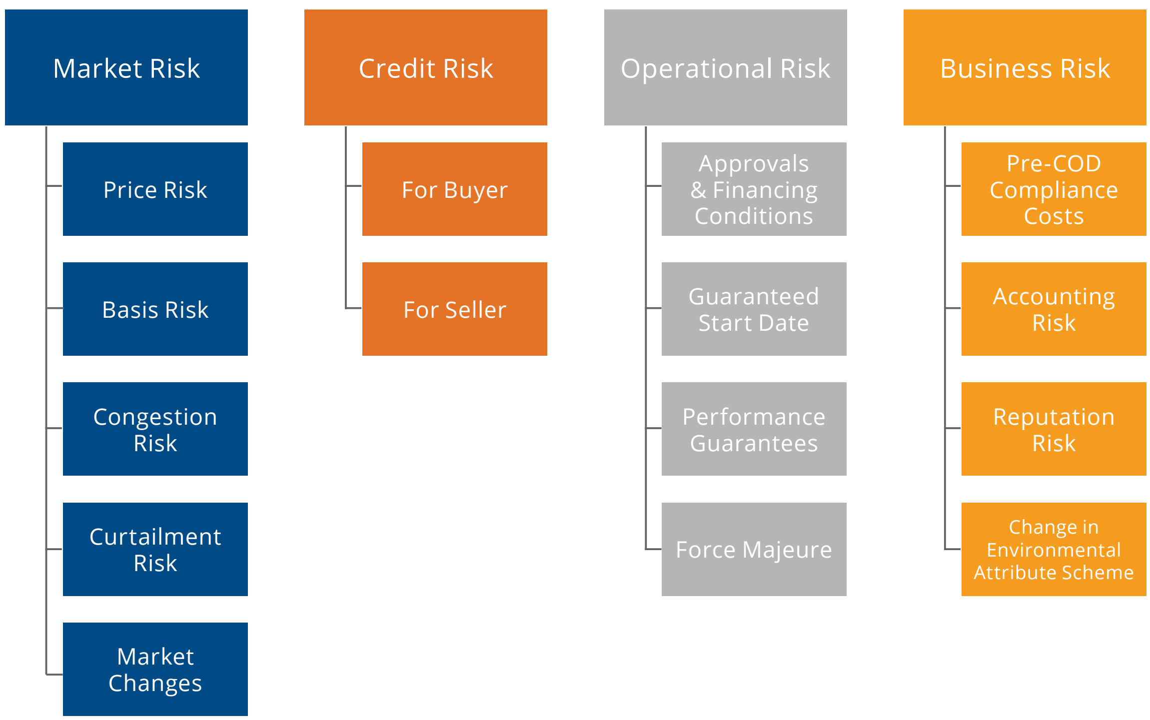

Figure 7. Risks in VPPAs

Source: Rocky Mountain Institute

This guide is not intended to explain each risk. The Business Renewables Center's Risk Allocation Primer is over 70 pages long, and is available to members.[5]

Component #2: Allocating risks

For context, sellers seek to develop financeable projects and have to manage lenders' needs while working with non-utility buyers. Lenders' needs are based on the established project-financing markets, which were built with utilities and central procurement agencies as off-takers. Non-utility buyers can have significantly different appetites and abilities to manage certain risks.

Buyers' objectives will determine their alignment on contract risks. Typically, buyers seek to manage downside risks being introduced into their procurement models. Buyers have been known to sacrifice upside/potential benefits to limit downside risks.

The risk allocation process is the essence of contract negotiation, and as mentioned in Off-Site Challenge #1: Complexity, a robust network of consultants and brokers have developed deep skills in working with both parties to arrive at a mutually desirable position.

One approach to managing risk has been through an aggregated-buyer transaction, wherein multiple buyers each procure a small percentage of a project. The buyers are seeking to limit the exposure to market specifics impacting an individual project, and to build a portfolio to smooth risk exposure. One such example is a group of four corporate buyers who developed a consortium to jointly procure from multiple projects.[6]

Off-Site Challenge #3: Economics

The economics challenge has two components: the movement of wholesale electricity costs as compared to the fixed price in a VPPA, and how a buyer "sells" an off-site transaction internally to stakeholders.

Component #1: Reduced wholesale electricity costs

A significant challenge in the market has been the sharp drop in natural gas prices, which in the U.S. have become highly correlated to wholesale electricity costs, as shown in Figure 8.

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[5] Business Renewables Center, "Primers." http://businessrenewables.org/primers-and-guides/

[6] Business Renewables Center, *The Dutch Wind Consortium: Successful Aggregation Of Corporate Renewables Buyers In Europe* (2017). http://businessrenewables.org/wp-content/uploads/2017/12/BRC_DutchCaseStudy.pdf

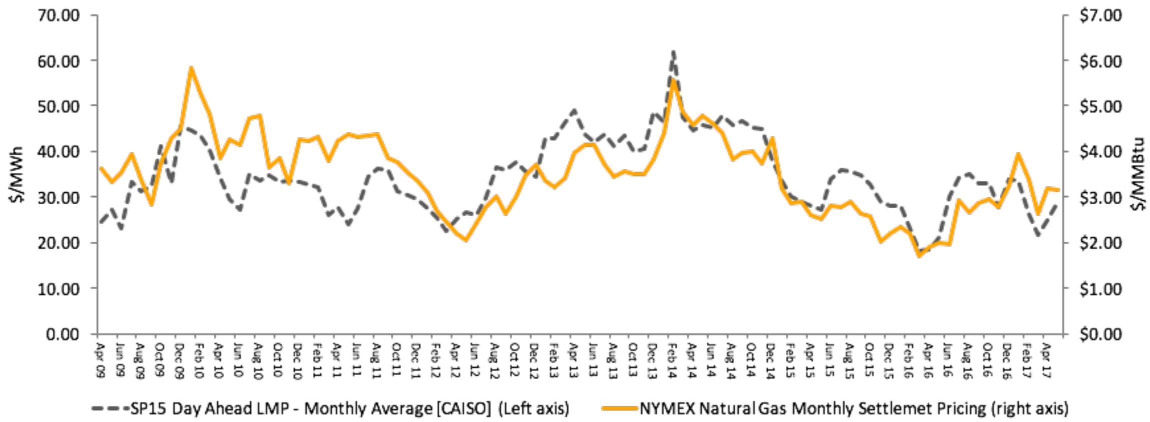

Figure 8. Natural gas prices and wholesale electricity costs

Data source: S&P Global Markets and Direct Energy[7]

Keep in mind the cash flows within a VPPA, in which the buyer receives the (variable) wholesale electricity price and pays a fixed price to the renewable energy project to procure high quality EAs. Should the wholesale electricity price fall below a VPPA's fixed price, the contract would be "out of the money" and could be costly to the buyer, depending on the contract details and hedge effectiveness.

It should be noted that renewable energy costs are continuing to decline, eroding any gap between costs from legacy infrastructure and new renewable energy projects. Indeed, according to Lazard, in many regions, "the full-lifecycle costs of building and operating renewables-based projects have dropped below the operating costs alone of conventional generation technologies such as coal or nuclear," as shown in Figure 9.

[7] S&P Global Market Data (CAISO LMP data); Direct Energy, "NYMEX Natural Gas Futures Settlement History. https://business.directenergy.com/market-insights/nymex-settlement-history

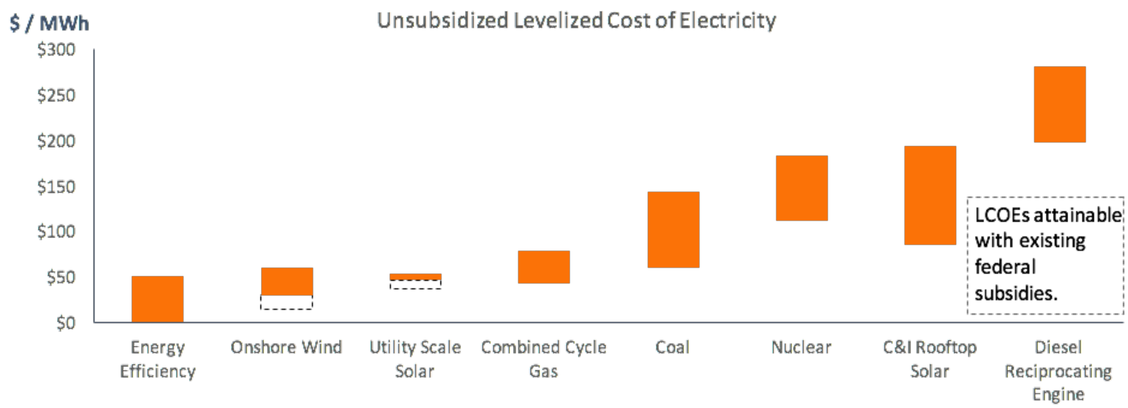

Figure 9. Unsubsidized levelized cost of electricity

Data source: Lazard[8]

The context in Alberta is different with the expectation that electricity prices will continue rise from their all time low. This is discussed in the next section on details of the Alberta market.

Examples from the field prove Lazard's analysis: three utility-scale wind projects announced in Alberta on December 13, 2017 had prices of an average of 37 C$/MWh (29 US$/MWh, unsubsidized), the lowest prices for wind seen in Canada to date. While rates for non-utility buyers would likely be different due to risk allocation within the VPPA, these rates provide a starting point for analysis.

Additionally, it should be noted that VPPAs and other procurement tools only impact the electricity portion of the cost of power. As wholesale costs have declined and renewable energy helps to ensure long-term low costs, a recent trend has been a gradual increase in the contribution to total energy costs from the transmission and distribution portion of the utility bill. The contribution of capacity charges depends on the design of the capacity market in progress as described above.

Component #2: Internal "sell"

Experienced buyers have highlighted the importance of how an off-site EA procurement transaction is positioned to the buyer's internal stakeholders, requiring prudent economic analysis and adequate downside-scenario planning. The results should be communicated in terms of what the buyer will receive for the possible purchase price (over the term of the contract), such as EAs to meet established goals/targets.

[8] Lazard, *Levelized Cost of Energy Analysis 11.0* (2017). https://www.lazard.com/media/450337/lazard-levelized-cost-of-energy-version-110.pdf

Alberta’s electricity market context

Market factors

Electricity transactions and users

Alberta has a fully deregulated electricity market consisting of electricity generators, retailers and customers, as well as regulatory agencies such as the Alberta Electric System Operator (AESO). Any qualified electricity generator can make a competitive offer to sell its electricity into the wholesale power pool, any qualified retailer can buy and sell electricity from the wholesale market, and customers can choose their preferred retailer. Alberta’s deregulated market provides market participants with the flexibility to enter into agreements with one another, allowing non-utility buyers to sign procurement contracts with renewable energy generators.

Alberta’s electricity grid has historically consisted primarily of large-scale, centralized coal and gas electricity generating stations operated by independent power producers (IPPs) and large municipally owned utilities. In total, Alberta has approximately 235 electricity generating stations operated by 200 IPPs. The wholesale power pool is administered by the AESO.

End-use customers in Alberta are divided into two segments based on their total electricity consumption. Small customers use 250 MWh of electricity or less per year, while large customers consume more than 250 MWh per year. Small customers include residential, small commercial, and farm and irrigation users, while most large customers are industrial sites.

Small customers can purchase electricity from a competitive retailer or from the regulated rate option (RRO) provider for their area. Competitive retailers choose their own sale price, which is typically either a set price for a specific term or a floating price that varies with the wholesale market price. RRO providers must sell electricity to customers at the RRO price, which is set by a process defined by the Alberta Utilities Commission (AUC) and varies on a monthly basis in accordance with the electricity price in the wholesale market. These RRO providers were maintained as a regulated retail option to provide price certainty for customers when Alberta’s electricity market was deregulated.

Large customers can also purchase electricity from two types of retailers: competitive retailers, or the distribution system owner assigned as the default supplier for their area. Unlike the RRO provider for small customers, the distribution system owner can set its own prices and is simply the default provider for large customers that do not specifically enter into an agreement with a competitive retailer.

Large and small customers alike must pay distribution and transmission costs in addition to the price charged by their retailer.

It is also possible for large and small customers to purchase electricity directly from the wholesale market as a "self-retailer." Self-retailers purchase power to meet their own load requirements, but do not sell electricity to other customers. Self-retailers pay the pool price for electricity plus a trading charge to compensate AESO for operating the pool market. To become a self-retailer, the customer must register as an AESO power pool participant and obtain access to distribution and transmission lines. As the self-retailing route requires some attention to detail, a number of companies offer services to help customers administer the process but typically only buyers with large loads benefit from self retailing due to the added complexity and cost.

In 2013, 18% of large industrial customers purchased their electricity through the self-retail option, making up 30% of the total electricity consumed by large customers. Some small customers take part as well, with 6% of small commercial customers purchasing self-retail electricity in 2013, comprising 10% of the total electricity consumed by that customer segment. Very few farm/irrigation and residential customers partake in self-retailing. Those industrial and commercial customers that have experience navigating the wholesale market and are more sophisticated in terms of their knowledge of Alberta's electricity system may be better prepared to enter into non-utility deals/off-site PPAs.

Electricity demand

Alberta's internal electricity demand in 2016 was 79,560 GWh, including system load and behind-the-fence load. System load is the amount of energy delivered to end-use customers through the transmission and distribution system, including transmission losses. Behind-the-fence load is the amount of electricity demand in Alberta that is met by on-site electricity generation. System load is most relevant to understanding the potential for off-site PPAs in Alberta, as it represents energy demand that is currently met through the electricity grid. System electricity load in Alberta in 2016 was 53,843 GWh and has been steadily increasing over the past few decades as seen in Figure 10.

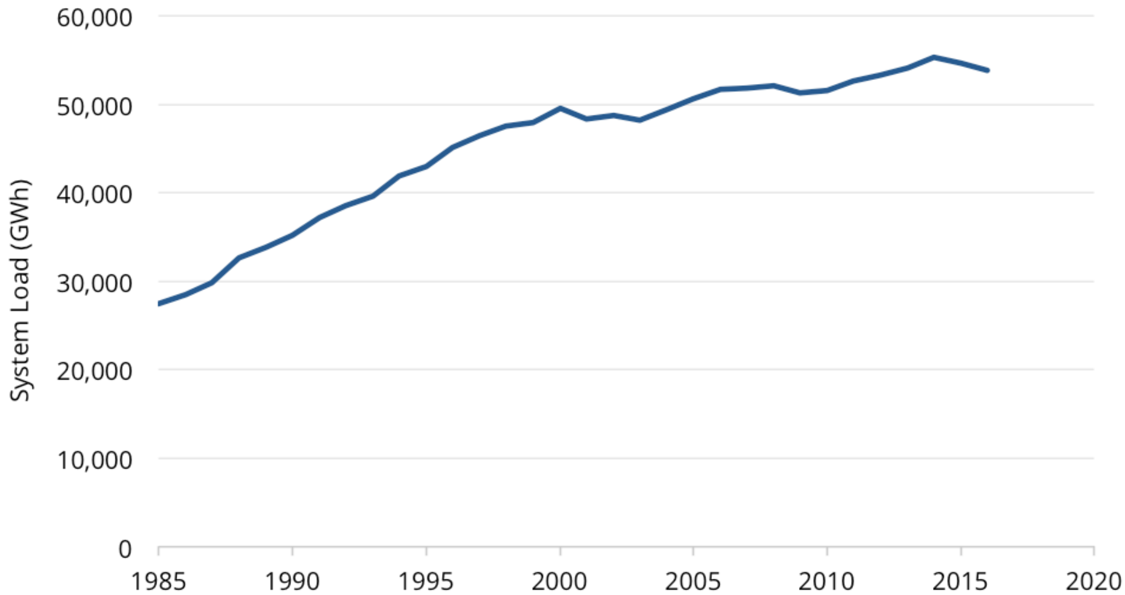

Figure 10. Alberta annual system load

Data source: Alberta Utilities Commission[9]

Industrial customers are the largest consumers of electricity in Alberta (excluding on-site generation), with 51% of system demand coming from industrial customers in 2016. Commercial customers are the next largest consumers, at 27% of system demand. Residential customers are responsible for 18% of demand and farms account for the remaining 4% (Figure 11). This demand breakdown between customer types has been stable over time.

[9] Alberta Utilities Commission, *Electric Energy Distribution Sales and Number of Customers* (2017), 1. http://www.auc.ab.ca/market-oversight/Annual-Electricity-Data-Collection/Documents/2017/Sales%20History.pdf

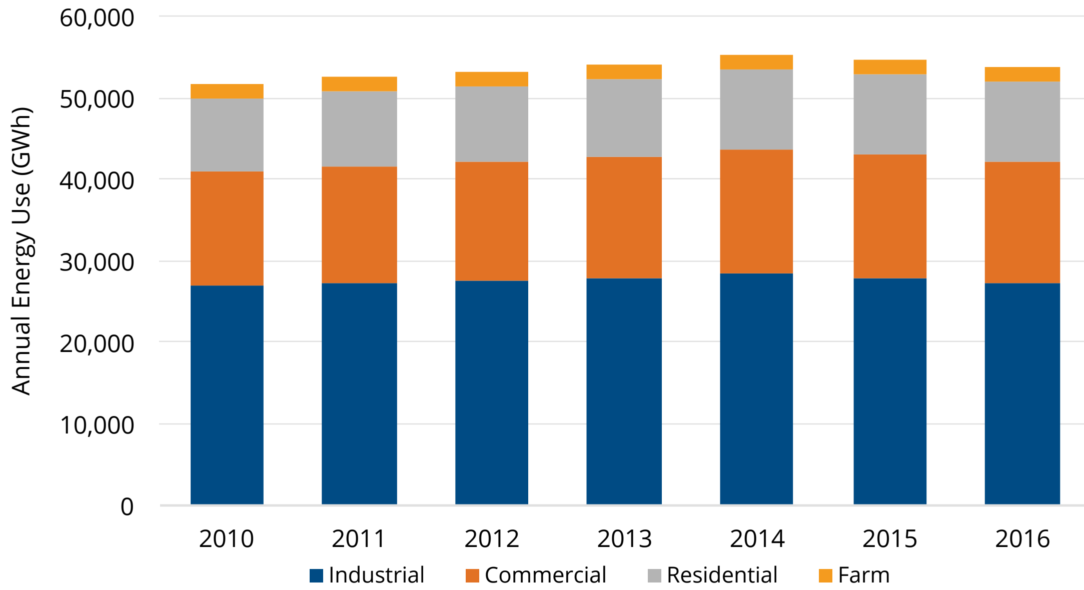

Figure 11. Alberta energy use by customer type

Data source: Alberta Utilities Commission[10]

While industrial customers comprise the largest portion of electricity demand, they are the smallest customer group at just 36,492 customers. Similarly, commercial customers represent 27% of system demand, but only 10% of Alberta's customer base (Figure 12). Having 12% of customers be responsible for 78% of electricity demand is favourable for sellers looking to enter into non-utility deals, because one customer could agree to off-take a significant amount of electricity.

[10] Ibid.

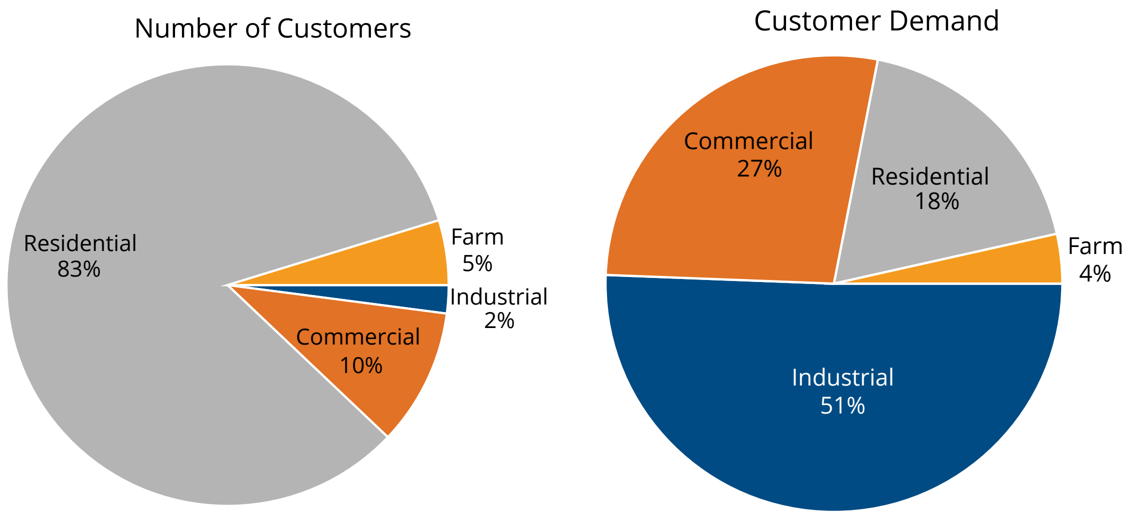

Figure 12. Customer types by number and demand share

Data source: Alberta Utilities Commission[11]

Wholesale prices/market dynamics

Alberta's electricity generation was fully deregulated in 2001, when the majority of electricity generation was produced from coal-fired power plants. Prices have oscillated between ~$40 and $90 in the period from 2002 to mid-2014 (see Figure 13) with both the demand for electricity along with the supply of other generation including gas-fired (cogeneration, combined-cycle, and simple-cycle plants) growing in parallel.

[11] Ibid.

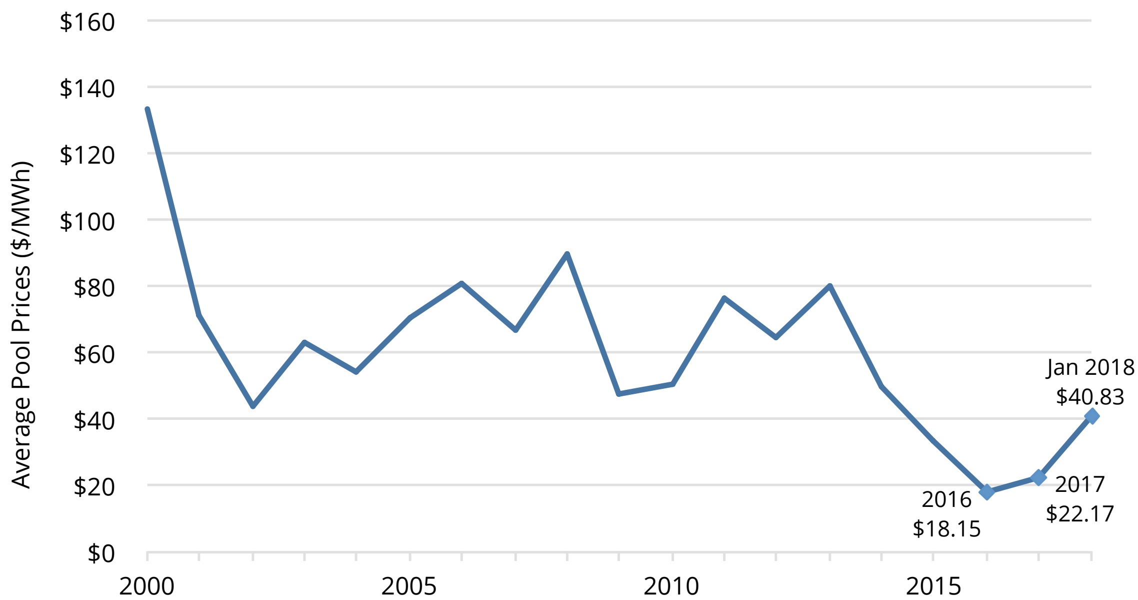

Figure 13. Historical pool prices in the Alberta market

Data source: AESO[12]

The sustained decline in global oil prices leading to lower electricity-demand growth than expected in Alberta, along with an increase in capacity from additional cogeneration units, led to a supply imbalance in the Alberta market beginning in late 2014. This trend then dominated the wholesale electricity market, with prices dropping further through 2016 and 2017.

However a reversal of this trend has been seen as the average pool price in January 2018 rose to $40.83/MWh. One coal generator was retired and a second was mothballed on January 1, 2018 (Sundance 1 and 2, 540 MW total) and further units are scheduled to be mothballed in 2018 and 2019. Additional coal generators have announced intentions to retire ahead of the required dates, and the rising carbon price will push costs for the more carbon-intensive coal generators higher. The market is expected to rebalance over the next years with upward pressure on the wholesale price due to tightening of supply — but forecasts for prices range depending on assumptions. The decision to proceed with conversion of coal plants to natural gas or construction of new natural gas plants remains an open question.

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[12] Alberta Electric System Operator, “Transmission Rate Impact Projection Workbook,” June 2014. http://www.aeso.ca/transmission/30685.html

With a rebalanced market and the ultimate phase-out of coal-fired power in the province, it is possible that Alberta could follow other deregulated markets in North America where natural gas has become the fuel type driving electricity prices, also known as the marginal-price fuel. If this is the case, then prices could rise if natural gas prices rebound from their all-time low.

Market structure

Alberta's electricity market is currently an energy-only market; generators are paid solely for the electricity they sell. In November 2016, the Alberta government announced that it will be adding a capacity market as of 2021, in which generators will also be paid for providing electricity-generation capacity. The design of the capacity market is ongoing with a final version of the design expected in summer of 2018, but it is expected that renewables not receiving a contract through the government Renewable Energy Program will be able to participate, as in other capacity markets.

Beginning in 2021, the total price for electricity will reflect both energy and capacity prices. The total wholesale price is expected to increase over time as previously projected, with no material change anticipated as a result of the addition of the capacity market (though price volatility may be decreased). This means, however, that the energy portion of the wholesale price is expected to increase less over time than previously forecast by AESO. At this point, it is unknown whether the energy and capacity prices will be combined into a single wholesale electricity price or reflected separately.

The capacity market addition should not preclude a non-utility procurement arrangement between a buyer and a seller. However, if the price to be paid for electricity under the agreement were linked to the wholesale price, the parties would need to be clear on whether they are referring to the energy price, the capacity price, or the total wholesale price.

Regulated rate option cap

In November 2016, the Government of Alberta set a $68/MWh cap on the price of the regulated rate option (RRO), effective from 2017–2021. The stated intention of the cap is to provide certainty to customers during the period of market transition. If the unadjusted retail electricity price exceeds $68/MWh., government will make up the difference to the RRO provider.

The RRO cap may affect the electricity price paid by small customers that purchase electricity from an RRO provider. It will not affect the wholesale market price for electricity, and therefore would not affect a non-utility agreement.

Environmental factors

Coal phase-out

The Government of Alberta and the Government of Canada have both announced a phase-out of coal-fired power by 2030. While not directly impacting the non-utility procurement of renewables, the phase-out of coal power in Alberta presents an opportunity for direct impact on the grid mix. In the absence of efforts to increase the share of renewable generation above the 30% committed to, there is an expectation of significant natural gas build-out, including conversion of existing coal-fired power plants to natural gas generation. Non-utility procurement could displace new gas generation — supporting a strong claim of additionality.

Carbon pricing

Large emitters producing more than 100,000 tonnes of GHG emissions per year have historically been regulated under the 2007 Specified Gas Emitters Regulation (SGER). The SGER required these large emitters to reduce their emissions intensity on a yearly basis compared to their historical performance, with options to trade requirements with other regulated entities, purchase offsets, or pay a fee, starting at $15/tonne and rising over time to $30/tonne in 2017. While renewable energy projects were not regulated under SGER because they did not meet the emissions requirement, renewable energy projects could generate approved offsets that regulated entities could purchase to meet their obligations under SGER.

As of January 2018, SGER has been replaced by a new Carbon Competitiveness Incentives (CCI) regulation. This program uses an output-based allocation system, in which a common emission standard (in tonnes of CO_2/MWh) is established for all electricity generators. Generators will be allocated enough allocations/emissions performance credits (EPCs) to cover the amount of emissions they would produce if their facility operated at the common emissions standard for their industry, based on the number of MWh of electricity they generate. Facilities with a higher emissions intensity can purchase more emissions performance credits (EPCs), purchase offsets, or make a payment to the Climate Change and Emissions Management Fund. Facilities that produce fewer emissions can sell their extra EPCs to other regulated entities either within the electricity sector or in other covered sectors.

While the CCI system continues to apply only to large emitters (>100,000 tonnes/yr), renewable energy projects will still be eligible to generate offsets as under SGER or have the option to opt into the CCI system and be granted allocations/emissions performance credits. Under the CCI system, renewable energy projects will therefore receive the defined electricity-industry standard of 0.37 emissions performance credits (equal to one tonne of CO_2e per credit) per MWh produced, like all other (fossil) electricity generation in Alberta. Starting in 2020, the standard of 0.37 tonnes/MWh will decrease at a rate of 1% per year. Renewable electricity projects can then sell these credits to other regulated entities that need to meet their obligations.

It should be noted that renewable energy projects cannot participate in the Renewable Electricity Program (REP), designed to procure energy to meet the 30% target, if they are also participating in the offset or CCI system. In other words, a renewable electricity project cannot receive financial support through the REP if it is being allocated emissions performance credits, and vice versa.

The primary implication for non-utility procurement of renewable energy in Alberta relates to the generation of offsets or EPCs by renewable projects. Renewable energy projects not participating in the REP will be eligible to either generate offsets or receive 0.37 tonnes of emissions performance credits per MWh they produce. The value of each emissions performance credit is expected to approximate the carbon levy (currently $30/tonne and rising to $50/tonne by 2022) minus transaction costs. This translates to a maximum value for EPCs of $11.10/MWh in the first year rising over time as the carbon price rises. The offset value granted to renewable energy projects will be determined by the offset protocol currently under review. For buyers with direct carbon-compliance obligations from industrial operations, the transactions costs are expected to be quite low.

Depending on the intention/desires of the buyer, either the EAs can be monetized through EPCs/offsets to contribute to the economics of the project, or the EAs represented by the EPCs/offsets could be purchased and retired. Only in the latter case can the buyer claim to be purchasing/using renewable electricity. Both are valid approaches depending on the goals of the buyer.

Alberta’s renewable energy target

The 2016 Renewable Electricity Act established a target that 30% of the electricity generated in Alberta each year be generated from renewable energy resources by 2030. The main mechanism to meet this target is the newly established Renewable Electricity Program operated by the AESO. The regulations for the act are currently in draft form.

The 30% target could be a barrier to non-utility procurement of renewable electricity in Alberta for buyers who take a very strict definition of additionality such that they only consider a renewable energy project to be additional if it is above and beyond the amount of renewable energy generation that would have existed in the region without the PPA. Therefore, to be additional, projects must result in more renewable energy generation beyond the 30% target. See the discussion of additionality in the section “Procurement of renewable energy,” above.

This is a potential issue because the language in the Renewable Electricity Act implies that any renewable energy project in Alberta, whether procured through the REP or not, could count toward the 30% target. The simplest way to address this issue would be for the Alberta government to include provisions in the regulations pursuant to the Renewable Electricity Act stating that renewable electricity directly procured from non-utility organizations in Alberta does not count toward meeting the 30% target, or provide an option for project proponents to retire the renewable attributes of a project such that they aren’t counted towards the total target.

Renewable electricity prices

Recent winning bids for renewable energy projects give a benchmark for expected prices. Nearly 600 MW worth of wind projects were procured in December 2017 by the Government of Alberta at a weighted average price of $37/MWh. The range of winning-bid prices was from $30.90 to $43.30/MWh. These prices, without any subsidies, are the lowest-price wind contracts procured to date in Canada. It should be noted that rates for non-utility buyers would likely be different, driven by risk allocation within the VPPA; these rates are a starting point for analysis.

Additionally, as discussed above in the section “Addressing off-site EA procurement market challenges,” VPPAs and other procurement tools only impact the electricity portion of the cost of power. As wholesale costs have declined and renewable energy helps to ensure long-term low costs, a recent trend has been a gradual increase in the contribution to total energy costs from the transmission and distribution portion of the utility bill. The contribution of capacity charges depends on the design of the capacity market in progress as described above.

Other supportive renewable energy policies

Renewable energy is increasingly receiving attention and support at both the provincial and federal levels, which could provide support for non-utility procurement.

The Alberta government recently announced $1.4 billion dollars in innovation funding supported by the Climate Leadership Plan, with $400 million dedicated to loan guarantees for renewable energy and energy efficiency projects that should encourage companies and investors to pursue renewable energy projects that might otherwise have been seen as too financially risky.

The federal government has also indicated its intention to support deployment of renewable generation across the country through the Pan-Canadian Framework on Clean Growth and Climate Change, but additional details have yet to be provided. It is possible that some support could also assist in non-utility procurement.

Qualitative factors

There are a number of different reasons why organizations in Alberta might be interested in non-utility procurement. Many of these reasons are common to organizations in other regions, but Alberta-specific drivers are also included here. These could include (but are not limited to):

- As a mechanism to meet internal sustainability targets, as well as brand and social governance goals
- To achieve goodwill benefits as being an environmental and climate change leader
- For carbon compliance under the CCI regulation through the ownership or sale of emissions performance credits or offsets that the renewable projects generate (Alberta)
- To provide certainty over long-term electricity prices
- To hedge against rising carbon prices/reducing carbon exposure
- To align with federal and provincial policy objectives
- As a mechanism to meet other goals such as sourcing from Indigenous corporations in cases where projects have an Indigenous partner, or supporting community development in cases where projects have a community partner (Alberta)

There are some additional reasons why organizations in Alberta might be hesitant to engage in non-utility procurement. As in the case of qualitative drivers, some are similar to organizations in other regions, but could also include Alberta-specific drivers. The list here is not exhaustive but is informed by interviews conducted with potential market participants:

- Buyers may be hesitant to enter into long-term contracts.
- The process could be viewed as costly/lengthy, especially if not well understood within the organization.
- There could be risks, real or perceived, around marketing/promoting support for renewable energy in a province with a strong fossil fuel industry.

Transacting for scale: Buyers' roadmap

Off-site transactions allow a buyer to procure at scale and meet goals/objectives—a single transaction can result in material progress toward a target. The experience gleaned from over 100 announced off-site transactions with non-utility counterparts have created a wealth of knowledge on how a buyer can move from a position of considering sustainability goals/targets, to executing a transaction to meet subsequently set goals/targets.

With the wisdom of many experienced buyers, the Business Renewables Center has developed a buyers' roadmap, which is designed to:

- Guide buyers through the transaction process
- Inform project developers and service providers how buyers transact, and support the provision of high quality products and services.

The buyers' roadmap in Figure 15 plots nine stages, with two stages having multiple substages.

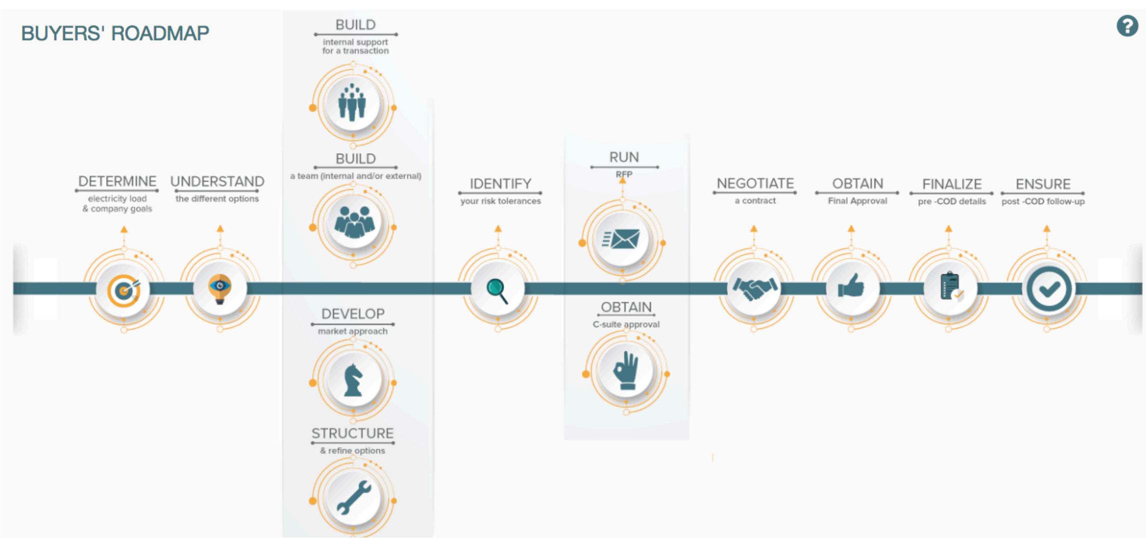

Figure 14. The buyers' roadmap

Source: Rocky Mountain Institute

This document will summarize the individual stages and highlight lessons learned throughout, drawing on resources and guides within the full buyers' roadmap.

Stage 1: Determine company goals & electricity use

Clear renewable energy goals are the primary driver for most large-scale renewable energy procurement by non-utility buyers. Clear goals will inform the business case presented when building internal support and hiring external support, risk discussion, and final approvals for a transaction.

Lessons learned

- It is important to have clear and established renewable energy goals. These may be derived from broader sustainability or GHG reduction goals or developed on their own.
- A key component of setting realistic and actionable goals is understanding the company's electricity use.
- Industry standards and norms can be a good place to start when considering setting goals and targets. An organization should consider if it wishes to be on the leading edge or a follower; this will help set the target/goal strength.
- Market expectations rise with time. It is important to reassess targets/goals to ensure the organization's position in the sector remains where desired.

Stage 2: Understand the options

After clarifying renewable energy goals, the next step is to determine a strategy. However, there is no one-size-fits-all approach to achieving energy or sustainability goals. A portfolio approach using different procurement mechanisms is considered the lowest-risk approach.

Lessons learned

- There is no one-size-fits-all approach to achieving energy or greenhouse gas goals.
- Most buyers choose to understand the available options and subsequently develop a high-level strategy for achieving their renewable energy goals.
- Given that these goals are usually fairly large and span multiple years, it is important to evaluate multiple strategies before settling on and outlining an approach.
- Specific to off-site EA procurement:
    - Size and portfolio: Can need be better met with a single, larger transaction or a portfolio of transactions? In some respects, this is a question of expediency vs. risk mitigation.

- Location: A project co-located with operations could bring community benefits and a potential hedge opportunity.

Stage 3a: Build internal support for a transaction

Executing a VPPA is a complex endeavour. The most complex part is likely to be the process of obtaining internal support and approval. To highlight this, the shortest known time in which a non-utility transaction was executed was six weeks. This was done with a team of two people (only one full-time) who had done one deal already. The same team took six months to close the first deal. The main challenge is to educate and bring on board not only the deal team, but also all the colleagues who have authority or influence on the final decision.

These transactions will be unfamiliar to many internal stakeholders; in fact, most of these stakeholders do not spend much time thinking about energy at all. As a consequence, obtaining their support will require a lot of communication and much internal iteration for them to become comfortable with the topic and feel that their concerns have been heard and addressed. Among these internal stakeholders, the accounting/finance department is of paramount importance. Depending on the company and deal structure, other executives such as business-unit leaders, procurement managers, and operations leaders may also play an important role.

Lessons learned

- When asked what they would do differently, every successful buyer says "more internal work and consultation."
- The internal approval process is often the most difficult and time-consuming aspect of completing a VPPA.
- It is important to hold initial conversations early on with key stakeholders, such as finance and accounting, in order to understand internal constraints and concerns.
- Key steps are undertaking an analysis of internal stakeholders, initiating conversations across verticals, and determining who must give ultimate approval and when to engage that person.
- Identify and cultivate a deal champion. Depending on organization size and structure, this may be a team of people or an individual, but the champion will be responsible for getting ultimate approval by the CFO or another necessary person or group.

- Recognize the organization's structure—some ultimate decision-makers prefer to be brought into the process early on and their approval may be required before even starting the procurement process.

Stage 3b: Build a team (internal and external)

Assembling an internal deal team and identifying necessary external support are critical steps to ensure the required skills and capabilities are present to execute a transaction and navigate internal processes. Deal teams typically consist of three layers:

- The core of a few individuals, including the deal champion.
- The internal support of technical experts who contribute to specific areas.
- The external support of additional experts contributing to specific areas.

Lessons learned

- Team composition:
  - Teams must have the subject-matter expertise necessary to analyze options, manage the process, and execute the deal.
  - Teams should represent different company verticals to effectively understand and address the perspectives and concerns of those groups.
  - Teams should have ultimate access to the relevant decision-makers.
- Skills and capabilities must include the ability to move through the buyer's internal approval process.
- Undertake an honest determination of in-house skills, and evaluate different options to hire external support and fill any gaps.
- Almost all teams include some level of external support, even highly experienced buyers.

Stage 3c: Develop market approach

The market approach is one level deeper than the strategy formation discussed in stage 2. Market approach means the elaboration of high-level objectives into preferences/characteristics for the procurement.

The internal stakeholder engagement process will funnel toward a specific market approach. Additionally, external market inputs, such as receiving responses to an RFP, could alter (or confirm) the working strategy/approach.

Lessons learned

- This is an iterative process to continue the internal engagement, while informing a specific market approach.

- Questions of approach include location, new or existing project (i.e., additionality), project EAs, and aggregation.

Stage 3d: Develop specific transaction preferences

During the process of engaging internal stakeholders, building a team, and formulating a market approach, the preferences/characteristics of the transaction will solidify. These preferences/characteristics, together with the risk considerations discussed in stage 4, will inform the RFP issued in stage 5a.

Lessons learned

- Be willing to adapt or evolve understanding while going through this process, and feeding these learnings back to stakeholders.
- Develop, test, evolve, and retest specific preferences/characteristics of the transaction sought.
- The types of preferences/characteristics to consider can include location, technology, size (capacity or annual generation), EA treatment, timing, publicity and branding, accounting treatment, and contract tenor.
- Consider working with other buyers to procure collectively.

Stage 4: Identify risk tolerances

This stage comprises the process of determining an organization's risk tolerances with internal legal counsel and other relevant stakeholders. This involves understanding the major types of risks inherent in the transaction structure(s) of choice, what risks the organization is comfortable with, and how the risks could potentially be allocated between the buyer and project within the PPA.

In addition, buyers will consider if it may be appropriate to engage with market makers, banks, or reinsurers that may be able to warehouse certain risks. This depends on the organization's risk appetite.

Lessons learned

- All internal conversations to date lead towards defining risk preferences.
- Risk allocation is the principle conversation in transaction negotiation—key internal stakeholders need to ensure all risks have been analyzed, understood, and appropriately managed.
- Engage experienced external legal counsel.

Stage 5a: Run a request for proposals (RFP)

At stage 5a, the buyer proceeds to market with the mechanics of a procurement process. Typically, company policies will guide the exact requirements and the form of the procurement process.

Many buyers may find it difficult to coalesce internally around transaction preferences and risk tolerances when pursuing a PPA for the first time. Similarly, some buyers may develop such preferences internally but, due to a lack of prior experience, lack certainty that these preferences are realistic in the market. In these cases, issuing an RFI as a first step can provide insight into the range of options available that might meet requirements. In particular, appropriately constructed RFIs can obtain indicative pricing for a given set of preferences. Typically, responses to an RFI will be more general and high level than an RFP (a specific project proposal), and can help short-list suitable developer partners and shape the specific requirements or project details to be outlined in an RFP.

The key to running a successful RFP process is to be appropriately specific—allowing apples-to-apples comparisons of the proposals/responses while leaving room for innovation. Effective comparisons will depend on the abilities of responding developers to independently use consistent inputs in their financial models, allowing for a comparison of project suitability and economics.

Lessons learned

- Asking for extensive scenarios at RFI stage highlights uncertainty and devalues the buyer's request.
- Setting a clear RFI/RFP timeline and process will allow developers to understand what to expect.
- Explain motivations and intent; this helps developers understand the buyer's goals.
- Be exceedingly clear in request documents—every term and word is read and reread.
- It is okay to specify that responses may also include nonconforming proposals, should the project developer believe it has a particularly attractive alternative.
- The RFI/RFP should ensure the terms (including allocations of risks) are clear enough to ensure proposals/responses are directly comparable.
- Consider what additional information might be required to complete evaluation, e.g., information about the expected wholesale market prices relevant to each proposal.

- A proposal evaluation framework/guidance/scoring helps developers understand what is important to a buyer.
- Negotiation exclusivity can help both parties. Depending on the circumstances, it should be considered before going to market, and clearly communicated. Organizational procurement policies and practices should be subject to consultation.

Stage 5b: Obtain required approvals

Senior management within buyer organizations often require approval prior to formal commitment, for example: before signing a heads-of-terms agreement. Work in stage 3 should show the required internal process.

Lessons learned

- Initial approvals are often required to explore a transaction during stage 3 (this may be a provisional approval); final approval is often required before stage 7 (after negotiating the contracts).
- The strategy for obtaining approvals should be informed by early stakeholder engagement (stage 3a) and managed appropriately.
- The vast majority of buyers do not attempt to pitch the PPA internally to leadership in terms of its net present value (especially as a money-making program). It is far more common to pitch the PPA as a purchase necessary to achieve sustainability targets and to describe the reasonable downside risks of the purchase.
- It is very important to understand early on how the CFO/financial approver will assess the economics of the deal to avoid unnecessary frustration later in the process. Examples of two types of approach are:
    - Fundamental analysis: Some CFOs/financial approvers will rely on forecasts provided by specialized firms, such as Ventyx (ABB), Wood Mackenzie, or Platts (McGraw Hill Financial), and derive from that an understanding of the PPA's potential financial impact.
    - Short-term analysis and long-term risk assessment: Other CFOs/financial approvers do not trust long-term forecasts. They prefer to focus on short-term price analysis and long-term price-risk assessment. To assess the long-term risks, CFOs/financial approver could pursue one or more of the following options:
        - Hire an external consultant (e.g., an investment bank with energy trading experience)
        - Develop an in-house analysis of historical prices

- Create an in-house analysis of "reasonable worst case" scenarios.

Stage 6: Negotiate a contract

Following the short-listing of developer partners (typically one or two parties) transaction negotiation begins. VPPA negotiations predominantly relate to the allocation of risk with the contract. During the negotiation process, contract provisions are likely to change and terms could evolve beyond provisions established through internal stakeholder approval.

Experienced buyers keep a close eye on the organization's previously-agreed risk appetite (determined in stage 4), and ask if the terms and conditions outlined in the contract in line with the company's risk tolerances.

Lessons learned

- It is critically important to continue to work with all internal stakeholders—especially legal and accounting teams—to ensure that the final agreement aligns with the company's requirements.
- Financial management will expect the deal team to perform a detailed deal evaluation and risk assessment and share the results of their analysis for critical scrutiny.
- It is possible that, if too much risk is placed on the project, the project developer will be unable to obtain the necessary financing to deliver the project. Therefore, it is important for buyers to understand what is required to create a bankable PPA.
    - When corporate buyers negotiate PPAs with developers, they are, in effect, dealing not only directly with a developer but also indirectly with the financiers that will back the project—both lenders and equity investors.
    - Several instances exist wherein buyers have signed PPAs but found themselves without operating projects because the developer was unable to find viable financing because the PPA did not satisfy the expectations of lenders and investors.

Stage 7: Obtain final approval

Obtaining final approval could involve very different things for different companies: it could involve an intensive review, or it could be a formality. Individual process will depend on organizational structure and culture, and the level of past engagement and approvals.

Lessons learned

- Stay close to those surrounding key decision-makers, apprising them of transaction progress and receiving ongoing feedback.

Stage 8: Finalize pre-commercial operation date details

During the period following transaction execution and before the project reaches its commercial operation date, the parties have a chance to organize their public statements and establish processes for the operating phase.

Lessons learned

- Transaction promotion is very important to most buyers and usually occurs at this stage. All parties in the negotiations should ensure press release processes, etc. are considered before the close of the transaction.
- Ensure that the EA management process is clear and that each party understands its responsibilities.
- Buyers typically enjoy knowing the development and construction process of the project they are involved with. This helps buyers manage internal stakeholders.

Stage 9: Manage operations

In virtually all cases, the project developer or project owner will be in charge of technical asset management (including operations and maintenance, troubleshooting, etc.). Buyers will be responsible for managing the contract—particularly monthly PPA settlements and retiring/reporting EAs.

Lessons learned

- Transaction parties should consider the form and format of settlement statements. Developing a form before the first statement arrives can make this process easier on the buyer's internal systems.

- EA management and retirement can be more challenging than some buyers expect. External parties can be hired to manage these processes.