Financing of Renewable Electricity Projects in Atlantic Canada

Prepared for:

Atlantic Energy Gateway

Atlantic Canada Opportunities Agency

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Power Advisory LLC

John Dalton
jdalton@poweradvisoryllc.com
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1 Introduction and Purpose

The Atlantic Canada Opportunities Agency (ACOA) is conducting the Atlantic Energy Gateway (AEG) study to facilitate the development of Atlantic Canada's clean energy resources. As part of this initiative, ACOA engaged Power Advisory LLC (Power Advisory) to identify and analyze the challenges to financing of renewable energy projects by independent power producers (IPPs) in each of the four Atlantic Provinces. This study identifies and evaluates the key factors that affect the availability and cost of capital for Atlantic Canada renewable projects developed by IPPs. The purpose of this study is to identify the necessary economic and market conditions and appropriate policies and government actions to support renewable project financings under reasonable terms and conditions so that the Atlantic Provinces can take full advantage of the opportunities offered by the region's renewable and clean energy potential.

1.1 Report Outline

In this report Power Advisory reviews the key factors that affect the availability and cost of capital for renewable projects developed by IPPs and assesses the degree to which there are policies that can be employed and changes to market conditions that can be made to facilitate the financing of these projects so that the region's full renewable energy potential can be realized.

The report first reviews the level of renewable project development in each of the four Atlantic Canada provinces as well as the policies that support the development of these projects. Chapter 3 assesses the project attrition rate for renewable energy projects in Atlantic Canada to provide an indication as to whether it is more difficult to develop and finance renewable energy projects in Atlantic Canada than other regions. The chapter then review3s the results of and insights from a phone survey that we conducted with over 20 renewable project developers and financiers that are active in Atlantic Canada. Finally, Chapter 3 concludes with a review of the results of our literature search regarding the financing of renewable energy projects. Chapter 4 reviews the critical determinants of the cost of capital including critical project risks that must be managed by renewable project developers and can be reflected in project's cost of capital to the degree that they aren't adequately mitigated. Chapter 5 provides an overview of current capital market conditions and assesses the implications for financing renewable projects by reviewing terms that are available to project developers. Chapter 6 reviews financing options for Atlantic Canada, policies to facilitate financing, and financing approaches employed in other jurisdictions by reviewing various case studies. Chapter 7 reviews policies that can be employed to facilitate the financing of smaller renewable energy projects which pose the greatest challenge and then discusses policies that can expand the scope of provincial electricity markets. Chapter 8 offers descriptions of strategic policy options for further consideration by the AEG committee members and Atlantic Canada governments.

Appendix A is the Interview Guide that we used to survey renewable project developers and financial industry professionals regarding the challenges associated with financing renewable energy projects in Atlantic Canada. Appendix B summarizes our findings from these surveys. Appendix C provides a broader review of policies to facilitate the financing of larger renewable energy projects developed by IPPs.

2 Review of Renewable Project Development in Atlantic Canada

This section provides a review of the level of renewable project development by IPPs and the major policy initiatives and programs to promote the development of renewables that have been implemented in each Province in Atlantic Canada. Finally, the major transmission interconnections in the region are identified and contrasted with peak load and existing generating capacity to provide an indication regarding the potential implications of market size and existing transmission infrastructure on renewable project development.

2.1 New Brunswick

Currently 28% of the electricity consumed in New Brunswick comes from renewable resources including hydroelectric, wind and biomass generation.[1] The vast majority of this is provided by seven hydroelectric facilities providing 895 MW, which are owned and operated by NB Power. Other renewables include 294 MW of wind generation developed by IPPs and a 38 MW biomass project at the Twin Rivers Paper Company. The output of these wind projects was procured by NB Power under two separate RFPs.

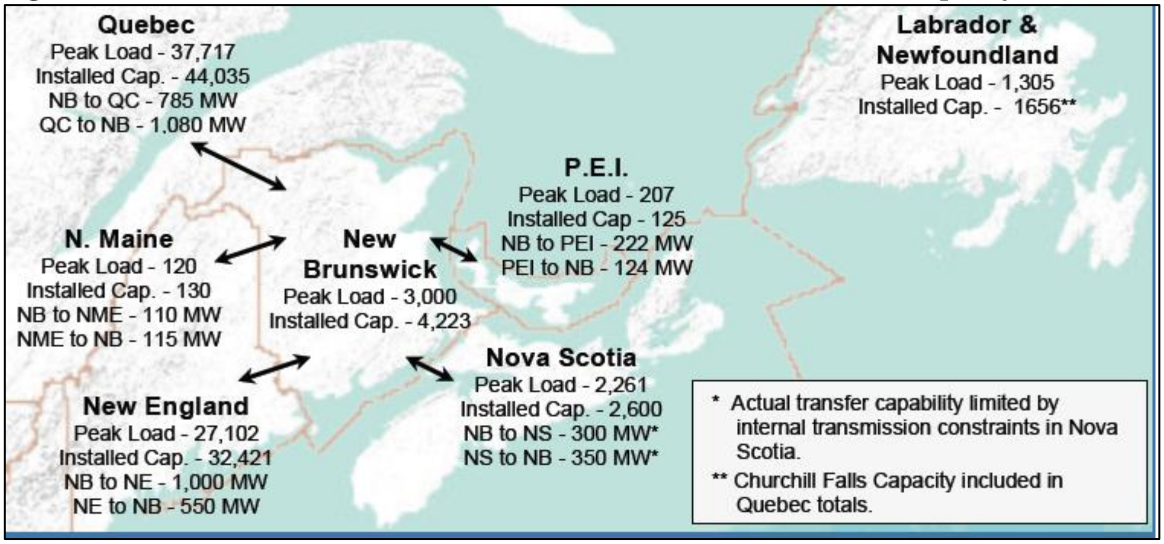
In October 2011, the New Brunswick Government released its *Energy Blueprint* which creates a new Renewable Portfolio Standard of 40% of NB Power's total in-province sales by 2020. With respect to renewable energy initiatives, the *Energy Blueprint* calls for: (1) supporting local and First Nations small-scale renewable projects; (2) integrating wind generation in the most cost-effective and efficient manner; and (3) supporting solar, bio-energy and other emerging renewable energy technologies. The *Energy Blueprint* also outlines a Large Industrial Renewable Energy Purchase Program under which NB Power would purchase the output from renewable energy projects owned by large industrial customers. The *Energy Blueprint* also indicates that "NB Power will procure new renewable energy resources through competitive Requests for Proposals (RFP) and projects will be evaluated on criteria to be released prior to each RFP. These criteria will include the net economic and social benefits to the community, cost of energy production, rate of return, business plans, size of project, and cost of integrating the generation into the grid."

As is evident from Figure 1, New Brunswick is well connected with the rest of Atlantic Canada and is the only province in the region that is directly connected with New England. Five of the six New England states have renewable portfolio standards which require 18 TWh of renewable energy by 2020, greater than the total forecast energy requirements of New Brunswick and PEI.

New Brunswick has an independent system operator which serves as the balancing authority for New Brunswick, Northern Maine and PEI. Under the *Energy Blueprint* it will be folded back into NB Power.

[1] New Brunswick Department of Energy, *The New Brunswick Energy Blueprint (Energy Blueprint)*, October 2011, p. 20.

Figure 1: Transmission Interconnections vs. Peak Load and Generation Capacity



2.2 Newfoundland and Labrador

Newfoundland and Labrador has three IPP wind projects which provide about 54 MW. The Island of Newfoundland, where these projects are located, isn't currently connected with the Eastern Interconnect. However, Nalcor Energy has proposed the development of Muskrat Falls, an 824 MW hydroelectric facility located in Labrador. As part of the development of this project, Emera Energy would receive about 1 TWh of energy per year from the project and in return build transmission, the Maritime Link, which would connect Newfoundland and Nova Scotia. The Maritime Link will connect the Province to the rest of Atlantic Canada.

2.3 Nova Scotia

About 17% of Nova Scotia's electricity supply is provided by renewable energy resources, including almost 400 MW of hydroelectric and tidal generation owned and operated by NSPI.[2] This includes about 300 MW of wind generation, of which about 82 MW are owned by NSPI.[3]

Nova Scotia has a requirement of 25% renewable electricity generation by 2015 and a target of 40% by 2020. This includes an additional 300 GWh from IPPs to be procured under an RFP process administered by an independent Renewable Electricity Administrator, with an equivalent amount of renewable energy to be developed by NSPI. In addition to renewable energy development by IPPs and NSPI, Nova Scotia has implemented a feed-in tariff for community renewable energy projects (COMFIT) and a feed-in tariff for Developmental Tidal Arrays.

As of February 2012, over 95 applications have been submitted and twenty, representing about 50 MW, have been approved by the Province. Of the twenty COMFIT applications that have been approved ten are being developed by Community Economic Development Investment Funds (CEDIFs), five by municipalities, one by a university, one by a First Nation, two are for Tidal

[2] http://www.nspower.ca/en/home/environment/renewableenergy/default.aspx
[3] A 31.5 MW project is under construction and scheduled to be in commercial operation in the first quarter of 2012.

Arrays, and one is an industrial biomass-fired combined heat and power project. Around 90% of applications have been for wind projects. Of these, most are large wind (>50 kW), with about ten percent of wind projects small wind projects. Several applications have also been submitted for biomass and in-stream tidal projects. Eleven of the approved projects are large wind for a total of 44 MW, six are small wind for a total of 73.5 kW, the two Tidal Arrays total 2.45 MW and the biomass CHP is 3.3 MW. The province expects about 100 MW to be produced by the COMFIT.

2.4 Prince Edward Island (PEI)

Reflecting its exceptional wind resource, PEI has 173 MW of wind capacity,[4] for an electricity system that has an average load of 145 MW.[5] Maritime Electric purchases 52 MW of wind generation from the PEI Energy Corporation's North Cape and Eastern Kings wind farms and 10 MW from the WEICan facility. As well, the City of Summerside has developed a 12 MW wind farm to serve a portion of the City's load. In addition, a 99 MW wind farm was developed and financed based on the sale of energy to New England which requires that the power be wheeled through New Brunswick.

Maritime Electric is part of the NB Power control area, which facilitates balancing. However, Maritime Electric is responsible for imbalances that it incurs on the NB Power system as a result of the variability of wind.[6]

In October 2008, the Government of Prince Edward Island announced the province's wind energy strategy, *Island Wind Energy, Securing Our Future: The 10 Point Plan*. The province's goal is 500 MW of wind power to be installed by 2013. The 10-point plan focuses on benefiting the local community and providing opportunities for developers by setting clear ground rules and establishing a fair, open and transparent process for developers.

[4] Including the 10 MW WEICan facility now commissioning.
[5] Including Maritime Electric and the City of Summerside jurisdictions.
[6] The wind in PEI and Northern Maine result in 502 MW of wind which must be balanced by NB Power, resulting in one of the highest proportions of wind generation in North America. (*Energy Blueprint*, p. 22)

3 Evidence on Financing Renewable Energy Projects in Atlantic Canada

The RFP posed three basic questions:

1) Is there a shortage of equity and debt financing available to renewable energy projects in Atlantic Canada and if so what financing vehicles can improve the availability of capital?
2) In what ways are there greater risks associated with renewable energy projects in Atlantic Canada than in other jurisdictions, including the rest of Canada? How can these risks be mitigated for investors? Are there gaps in the information that investors require?
3) Do projects developed in Atlantic Canada have disproportionately high technology risks (e.g., tidal projects)?

We have addressed these questions by surveying participants in the Atlantic Canada renewable energy market and by researching the market. We have also reviewed the available literature for information on the issues associated with financing of renewable energy projects in general and on such issues within Atlantic Canada. This literature review is also presented in this Chapter. However, prior to reviewing the findings from these interviews and this literature review, the attrition rate for renewable projects in Atlantic Canada is reviewed.

3.1 Project Attrition Rate Assessment

An important indicator regarding the health of the renewable project market in Atlantic Canada is the level of project attrition relative to other markets.[7] A higher level of project attrition indicates that there are greater project development risks in Atlantic Canada than other jurisdictions. One challenge with such an analysis is the lack of transparency regarding project development efforts which makes it harder to establish the level of project development activity.

A key determinant of project success is the market's need for renewable capacity. A region with favourable renewable resource potential, but relatively limited demand for renewable energy, is likely to have a higher proportion of proposed projects that don't get contracts and therefore don't achieve commercial operation.[8] Our focus is on projects that were awarded contracts in RFPs and demonstrated themselves to be attractive proposals or secured contracts under Nova Scotia's COMFIT or New Brunswick's Community Energy Policy, but weren't ultimately successfully developed given project development barriers. The experience in Nova Scotia, based on a 2007 Renewable Energy RFP, and New Brunswick, based on its two renewable energy RFPs, is reviewed below.

[7] Project attrition here refers to projects which succeed in RFP processes or otherwise obtain contracts but are never built.
[8] A number of developers made this comment, i.e., the primary constraint to successful project development efforts is the size of the market.

3.1.1 Nova Scotia's Experience

Nova Scotia Power Inc.'s (NSPI's) 2007 RFP was for 130 MW. Power Purchase Agreements were signed for 246 MWs, with 252 MW ultimately built. NSPI elected to contract with more than its procurement target to compensate for anticipated project attrition which it estimated to be 20 to 30% based on the experience in California.[9]

The additional 6 MW built versus contracted (i.e., 252 MW versus 246 MW) reflects the additional capacity provided by changes in wind turbines. Of this capacity, 81 MW was ultimately built by NSPI when IPPs were unable to deliver on their contractual commitments.[10] The developer of one of these projects (SkyPower) sold its interests in the project after its major equity investor Lehman Brothers was liquidated. Another project, Amherst Wind Energy Project, which was originally proposed by Acciona Wind Energy Canada Inc., has subsequently been sold to Sprott Power Corp. and is under construction.

Therefore, while all of the capacity that was contracted by NSPI under its 2007 RFP was built, the terms under which a number of these projects were constructed differed from those outlined in the original RFP. A primary contributor to these changes was the financial crisis in 2008 which caused an unprecedented increase in debt costs. This is shown in

Figure 2 which presents long term bond rates from 2006 to 2011 (through October) and shows how interest rates for Baa Bonds rated by Moody's Investor Services increased from about 6.5% in 2007 when proposals were submitted to around 8.5 % to 9% from October 2008 to April 2009.[11] This increase in financing costs made financing very difficult for projects that were attempting to secure debt during this period.

Given stakeholder concerns stemming in part from NSPI's acquisition of projects and with the RFP process, the Nova Scotia Government established an independent Renewable Electricity Administrator (REA) to administer future RFP processes for renewable energy resources.[12]

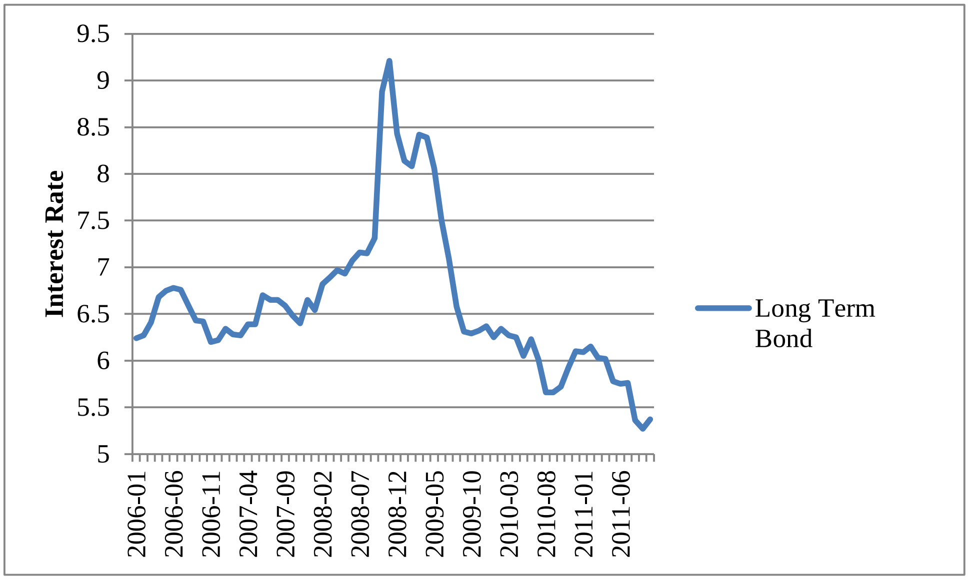
3.1.2 New Brunswick's Experience

NB Power has issued two RFPs for wind energy which have resulted in the development of 294 MW of wind generation from four projects including two at the same site.[13] A contract for 64.5

[9] Specifically, NSPI relied upon the following study performed for the California Energy Commission. "Building a Margin of Safety into Renewable Energy Procurements: A Review of Experience with Contract Failure" CEC 300-2006-004, January 2006.
[10] The Nuttby Mountain (50.6 MW) and the Digby Neck (30 MW) projects.
[11] These interests are for US bonds given the availability of data, but a similar increase in interest rates was experienced in Canadian bonds.
[12] Power Advisory was appointed as the REA by the Government of Nova Scotia. This model has specific challenges given that the REA designs the RFP; drafts the PPA; and selects the Proponents to be awarded PPAs, whereas, the PPA is ultimately executed by the IPPs selected and NPSI.
[13] These are 99 MW at Caribou Mountain, owned by GDF Suez; 150 MW at KentHills, owned by TransAlta, and 45 MW at Lamèque owned by Acciona. KentHills was contracted in two phases.

MW was awarded to Acciona Energy North America for a project in Aulac in early 2008.[14] This project hasn't been built, with delays reported to be attributable initially to adverse financial conditions and then permitting issues, i.e., Acciona must perform a two-year avian study given the project's location next to a marsh. Development delays prevented the project from participating in the ecoENERGY for Renewable Power Program, which in turn caused its PPA with NB Power to be terminated.

Figure 2: Long Term Bond Rates 2006 to 2011



Source: US Federal Reserve Data

3.1.3 Conclusions

Based on this review, Power Advisory believes that Atlantic Canada hasn't experienced higher project attrition rates than other parts of Canada. Project attrition rates in other markets range from about 13% (for the Renewable Energy Supply III RFP issued by the Ontario Power Authority) to the 20% to 30% experienced in California.

Project delays and the sale of project interests are attributable to overall financial conditions rather than any issues specific to Atlantic Canada. Interestingly, one developer that was associated with two projects which were considerably delayed was a large international renewable project developer which would be more likely to have the financial resources to weather such economic conditions.

3.2 Survey results

One of the three basic questions was whether there is a shortage of finance for renewable energy investment in Atlantic Canada and, if so, what policies might address these shortages. To help answer this question, we interviewed a wide range of market participants (developers and financiers) with experience or involvement in the development of renewable energy projects in

[14] http://www.nbpower.com/html/en/about/media/media_release/pdfs/WindAnnouncementJan28.pdf

Atlantic Canada. [15,16] All of the developers have been active in renewable resource development in Atlantic Canada, and most have also been active in renewable resource development elsewhere in Canada and the world.

Most of the interviews were conducted by telephone. At least two members of the project team participated in most of the interviews.

Both developers and financiers told us that location in Atlantic Canada does not create any disadvantage or differences compared to the rest of Canada in terms of availability of finance or of expertise on development of renewable electricity projects. A project in Atlantic Canada will be evaluated by financiers on the same terms as in the rest of Canada.[17] The evaluation will be by the same teams or by teams with the same knowledge of the industry. The initial challenges associated with financing projects in Atlantic Canada and some of the development difficulties were attributable to the more limited experience of local developers and smaller project sizes of the initial projects. This made it more difficult to realize economies of scale and some of the inexperienced developers structured projects in ways that made securing financing more difficult.

Several companies we interviewed have experience developing renewable energy projects in more than one province in Atlantic Canada and in other parts of Canada. They consistently said that the issues they faced in raising financial capital were the same in Atlantic Canada as elsewhere. Financiers are interested in the quality of the power purchase agreement (PPA), the creditworthiness of the offtaker, the experience and technical capability of the developer and the development team, and the financial stability of the developer.[18] They want to know that risks are identified, appropriately mitigated, and assigned to appropriate parties (i.e., the party that is best able to manage these risks). Large, experienced, well-supported renewable project developers, therefore, are able to access financing for their projects in Atlantic Canada under essentially the same terms as they are in the rest of Canada.

Some companies that have experience developing renewable projects in other provinces commented that some aspects of the development process are easier in Atlantic Canada. In particular, environmental permitting and aboriginal issues do not require as much time as they do in other jurisdictions.

Many of our interviewees pointed out that the conditions for financing renewable projects are quite different for small projects than for large projects, especially if the developer is also small

[15] Our interview guide is attached as Appendix A.
[16] The interview notes for those parties that authorized the release of the notes are attached as Appendix B.
[17] As discussed further below, this isn't necessarily true for small renewable projects which are more likely to rely on local lenders rather than lenders that specialize in renewable energy project finance and finance renewable energy projects across Canada.
[18] Not surprisingly, this is the same as in the US where a recent report by Mintz Levin found that "High-quality projects sponsored by experienced developers [which] have signed power purchase agreements ("PPAs") from credit-worthy off-takers will continue to secure project financing..." (*Renewable Energy Project Finance in the U.S.: 2010-2013 Overview and Future Outlook*, January 2012, p.7)

and relatively inexperienced.[19] The major financial institutions, banks and insurance companies, consistently said that they are generally not interested in projects where the total financing is below $50 million (a wind project of about 30 to 35 MW), though some said they might consider projects as small as $30 million.[20,21] The reason for this size threshold is simple: these institutions have finite resources to perform the required analysis and due diligence for projects and it costs them almost as much to do this for small projects as for large ones. Given the corporate expectation that they will lend a certain amount, they cannot afford to spend these limited resources on small projects. The institutions emphasized that this size threshold did not apply only to Atlantic Canada; it would apply anywhere in Canada or elsewhere.

Several interviewees also noted that, in their experience, small developers are more likely to have less development experience, to be more prone to overlook key risk factors or to make other mistakes in project structure, and in general to require more assistance from the lenders. This experience is not surprising as project developers are keenly focused on the success rate of their projects, and experienced developers will chase larger projects which offer larger returns for the same level of development effort as a smaller project. This experience reinforces the banks' reluctance to undertake relationships with such smaller developers. Further, small developers will have more difficulty accessing capital for such projects. For example, bank applications for smaller loans (say, up to $10 million) would be made to the local or regional commercial loan departments, which will not have expertise in lending to renewable developers and would not have ready access to such expertise from elsewhere in the bank. In addition, the due diligence and structuring costs can overwhelm the economics of a smaller project.

As the interviewees noted, the size of the market for renewable resources in Atlantic Canada significantly affects renewable energy development in the region. Since the overall Atlantic Canada electricity market is small relative to other areas, the amount of renewable capacity that can be integrated and the amount of renewable energy needed to meet a requirement like a Renewable Portfolio Standard (RPS) is also small. Therefore, the possible number of projects large enough to attract interest from these financial institutions is also small. The survey respondents said that this limits the number of companies that can participate in the market.

Some developers, especially those who are primarily focused on Atlantic Canada, commented on this limit on opportunities for larger developments in Atlantic Canada. They also noted that the limited number of winners in an RFP process, like those in New Brunswick and Nova Scotia, increases their risk of participation in the RFP process. The cost of participation in the RFP process for a small developer is a significant portion of its total resources. With only a few winners, and with competition from large developers, the small developer sees only a small chance of winning a contract. The small developers suggested that this is less of a problem for

[19] The previously referenced Mintz Levin Report offered a similar finding: "Project financing constraints are likely to disproportionately impact smaller projects, less established developers, and/or projects with higher technology or regulatory risks." (p. 7.)

[20] Some also said that they preferred projects at or below $100 million because above that size they will look for participation from other lenders. Some financiers preferred to finance larger projects, in the $200 million to $400 million range, but would look at projects as small as $50 million.

[21] This reflects a 70/30 debt/equity ratio and project capital cost of about $2,200/kW.

the large diversified developers who have a portfolio of existing and potential projects to draw from and can therefore afford to participate in an RFP and lose.

In general, smaller developers preferred a feed in tariff (FIT) process for acquisition of renewables. A FIT program would provide them with sufficient returns and with certainty of contract award, providing that they meet the FIT criteria.

By contrast, the larger developers generally preferred an RFP process. They said that such processes can produce better results for the buyers by ensuring the pricing is competitive. However, they warned that the winners in an RFP process based primarily on price might not be capable of building the project within the price they had bid. To guard against such outcomes, the developers urged that bidders in an RFP process be carefully screened before being qualified, including requiring them to post a significant deposit which would be forfeit if they are awarded the contract but fail to build the project.[22]

To summarize the results of our survey, the respondents told us clearly that, for comparable renewable energy projects, there is no difference between financing in Atlantic Canada and financing in the rest of Canada or in other jurisdictions. We heard that the most desirable projects from the financier's viewpoint are above $50 million in total finance, and most prefer sizes above that. The survey respondents then added that project development can be more difficult in Atlantic Canada because of the small size of the market and therefore the small number of projects of $50 million or more.

The respondents also commented on and suggested policies that could address these problems. These will be reported in the policy review section, Chapter 7 of this report.

3.3 Review of Relevant Literature

In addition to our interviews with market participants, we looked for available studies that would help us understand the difficulties and opportunities of financing renewable energy projects in Atlantic Canada. We had hoped to find at least one such study with a focus on Atlantic Canada. We could not find a regionally focused study, but we did find some studies dealing with the financing of renewable energy projects. We reviewed these studies to help identify the possible barriers to renewable energy project development, especially to financing such projects. This section reports on the studies we found most relevant and useful.

Renewable electricity generation projects are generally financed on a project finance basis. The overall conditions for finance of renewable electricity generation projects are the same as those for other projects: the project should be economically viable and its risks identifiable and manageable. The literature on finance for renewable energy projects also considers the needs of such projects to find additional sources of revenue (above the electricity market value of their output).

[22] Alternatively, the RFP evaluation process can consider the project development status as a measure of project risk as well as the pricing offered by the Proponent.

The two most helpful studies we found in the literature focused on evaluating the effectiveness of various policies aimed at improving the conditions of finance for renewable projects. One study[23] looked at policies applicable to the stages of project development, from development planning through construction and operation. At each of these stages, policies are available that can reduce risk and therefore the finance rates and overall cost of the project. The study uses a financial model to conclude that a combination of government policy measures can reduce the overall cost of renewable energy projects by up to 30%.

This study specified four different kinds of projects (20 MW onshore wind, 100 MW offshore wind, 1.5 MW solar PV, and 10 and 26 MW biomass) under the policy environments in six jurisdictions: France, Germany, the Netherlands, UK, California and Québec.

Table 1 below summarizes the findings of this report.[24] For several broad categories of policy support, the table shows the range of impacts on levelized unit energy costs, as computed using the financial model for all of the project types in all of the jurisdictions.

Table 1: Impact of Policies on Cost

POLICY AREA	COST REDUCTION IMPACT (%)
Long-term commitment to renewable support	10-30
Risk reduction by removing barriers	5-20
Risk reduction by risk sharing	5-15
Measures to reduce debt costs	5-10
Fiscal measures to increase net returns	2-20
Production support	2-30

Source: David de Jager and Max Rathmann

All of these impacts are attributed to the effect of the policies on the cost of finance. Therefore, the impacts of the different policy types cannot be considered cumulative; the maximum cost impact from a mix of these policies was estimated at 30%.

The study defines and gives examples of the policies it is modeling. Removing barriers means making permitting easier and having transmission available for grid connection when needed. Sharing risk refers to loan guarantees from government or direct project participation from government. Debt measures include low-interest loans direct from government or direct subsidies, typically available for projects which promote the development of new technologies. Fiscal measures range from accelerated depreciation to specific policies to reduce income tax liability (e.g., investment tax credits or production tax credits).

[23] David de Jager and Max Rathmann, "Policy Instrument Design to Reduce Financing Costs in Renewable Energy Projects", IEA Renewable Energy Technology Development, August 2008. http://iea-retd.org/wp-content/uploads/2011/10/Policy_Main-Report.pdf
[24] Ibid., pp. 3-5.

Production support measures enhance revenue during the production period and encompass many of the most effective policies in current use. They include FIT and feed in premium (FIP) programs,[25] direct production payments such as Canada's Wind Power Production Incentive and the ecoENERGY for Renewable Power programs. The study notes that well-designed FIT programs tend to have the greatest impacts on project prices by reducing development risks and financing costs. Such programs would evidence long-term commitments by making the period of the FIT contracts equal to the project's expected life as represented by the term of its financing.

In an effort to assess the reasonableness of these results, in particular the 30% cost reduction, Power Advisory used a financial model to calculate the difference between a typical fully contracted wind project and a similar merchant wind project in the price that would be required for the project to be viable. For the contracted project, there is no basis for distinguishing among the terms and conditions for a contract awarded under a FIT program or an RFP. Therefore, we assume that the financing assumptions wouldn't differ.

This analysis indicated that the price would have to be about 24% higher for a merchant project.[26] This supports the findings of the de Jager and Rathmann study cited above, but suggests that the cost reduction or price required would be 80% of level estimated in this study. However, Power Advisory believes that it would in fact be difficult if not virtually impossible to finance a renewable energy project in Canada on a merchant basis under current market conditions, i.e., low natural gas prices and a focus on quality by lenders.

Another study[27] took a similar approach but analyzed specific cases in specific jurisdictions. The cases were a large onshore wind farm in the US and Spain, offshore wind in Denmark, utility-scale PV in the US and Italy, and a concentrating solar tower in the US. The study started by computing the lifetime unit energy costs for each of these six cases and measured the impact on that cost of the possible renewable energy support policies.

The study looked at the impacts of the policies on finance costs as they would be seen by various classes of finance providers: lenders, mezzanine investors, balance sheet equity investors, and project finance equity investors. Each of these classes expects a different rate of return. As with the study cited above, the analysis used a cash flow financial model to determine the impacts of policies on cost and financial viability.

The study concluded that the three most important determinants of policy effectiveness are

1) The duration of the renewable support, especially the production support. If the debt term ends with the support term, the project must either maintain a much higher rate of

[25] Feed in premium programs pay a premium amount over the market price. Such programs therefore leave the renewable energy project exposed to market price risk, but with additional price support.
[26] The merchant wind project was assumed to have a 60/40 debt-equity ratio, 7% cost of debt, and 13% after tax cost of equity and cumulative debt term of 15 years, with the initial debt having a 5-year term and the second debt issuance having a 10-year term. The contracted wind project was assumed to have a 70/30 debt-equity ratio, 6% cost of debt, and 10% after tax cost of equity and debt term of 18 years.
[27] Uday Varadamjan, David Nelson, Brandon Pierpont, Morgan Hervé-Mignucci, "The Impacts of Policy on the Financing of Renewable Energy Projects: A Case Study Analysis". Climate Policy Initiative, October, 2011.

payment to amortize the debt earlier or take the risk of refinancing part way through the project life.

2) The degree of revenue certainty. A FIT or PPA at a fixed price are preferred to other supports like a FIP.
3) Risk perception. This is the perception of risk in the support policy. Good project management can mitigate other risks; for example, completion risk can be mitigated in the construction contract.

One other study provided some examples of financing relatively small renewable power projects.[28] Most of the policies in this study relate to the specifics of renewable power support in the United States through tax preferences and are not relevant to Canadian circumstances. However, the study also shows how these policies can combine with low-interest loans from government to make renewable power projects economically feasible.

We reviewed briefly several other reports but those described above contributed the results most useful for this project.[29]

3.4 Findings on the RFP Questions

Our findings from our survey of market participants and consideration of the success of renewable developers in Atlantic Canada has led us to some basic conclusions on the three questions posed by the RFP.

1) We find no shortage of debt or equity capital for renewable projects in Atlantic Canada as compared to Canada as a whole. Renewable projects in Atlantic Canada can access both debt and equity markets on the same footing as similar projects in other parts of Canada. Chapters 4 and 5 discuss the financial conditions for renewable projects generally and in Canada.
2) We find no inherently greater risks in Atlantic Canada than in other parts of Canada. However, we do find that the small size of the Atlantic Canada electricity market tends to mean that projects are likely to be smaller, and we find that developers of small projects do face difficulties in raising capital that are not present for large projects. Chapters 6 and 7 deal with financing options for Atlantic Canada projects and with potential policies to address problems with finance, especially for small renewable projects in Atlantic Canada.
3) We find no evidence of greater technical risks in Atlantic Canada than in other parts of Canada for projects using proven technology such as wind turbines or hydroelectric

[28] Mark Bolinger, "Community Wind: Once Again Pushing the Envelope of Project Finance", 2011, LBNL 4193-E

[29] For example, Mark Bolinger, Ryan Wiser, Naum Dargouth, "Preliminary Evaluation of the Impact of the Section 1603Treasury Grant Program on Renewable Energy Deployment in 2009", 2010, Lawrence Berkeley National Laboratory LBNL 3188-E; White Paper: "Renewable Energy Project Finance in the U. S.", 2010, Mintz Levin; International Conference for Renewable Energies, "Mobilizing Finance for Renewable Energies", 2007, Thematic Background Paper for conference Renewable Power Policy and the Cost of Capital, UN Environmental Program, Sustainable Energy Finance Initiatives; Dermot Duncan, "Project Financing Electricity Generation Projects in NSW with a Specific Focus on the Externalities to Renewable Generation, Dec. 2010, Crisp Legal.

generation. We note the interest in development of new technologies, specifically tidal power, but did not find evidence to indicate that its development in Atlantic Canada is more difficult than would be development of a similarly new technology elsewhere in Canada.

4 Review of Factors Affecting Cost of Capital

4.1 Introduction

An investors' cost of capital represents the minimum return or hurdle rate an investor needs to achieve for investing in the project, and this hurdle rate is influenced by what returns the investor expects or is able to achieve on investment in other projects with similar risk profiles.

The general framework for estimating the appropriate cost of capital for a company is based on an economic theory called the capital asset pricing model (CAPM), which is considered "the backbone of modern price theory for financial markets". [30, 31] CAPM begins with a risk free rate and provides a theoretical framework for estimating the appropriate return for the specific risk factors by observing the returns for other similar securities. In practice, investors start with the appropriate risk free or reference base rate (for debt investors) and estimate a premium above the base rate, using a combination of theory and judgment, that is necessary to compensate the investor for the additional risks above the risk free rate, as shown below.

Table 2: Components of the Capital Asset Pricing Model

<table>
<tr><th colspan="2">Cost of Equity and Cost of Debt[32]</th></tr>
<tr><td colspan="2">Cost = Risk Free Rate (equity) or Reference Base Rate (debt)[33] plus risk factors:</td></tr>
<tr><td>+ Impact of Project Specific Factors
+ Impact of Size and Liquidity
+ Impact of Other terms
+ Impact of General market conditions</td><td>For Debt capital, the total impact of these factors is known as the credit spread. For Equity, the total impact of these factors is known as the risk component of the cost of equity.</td></tr>
</table>

Source: Power Advisory

While the risk free rate can vary significantly, changes in the risk free rate are not within the developers' control (see Section 4.2). Experienced project developers focus on minimizing the credit spread, as renewable projects are predominantly financed with debt capital (70% to 80% of total capital).[34] Reducing the cost of debt will reduce the cost of equity for the project, which will in turn reduce the cost of financing the project and the minimum power price required to keep the

[30] Merkowitz, Miller and Sharpe were jointly awarded a Nobel Peace Prize in Economic Sciences in 1990 for their pioneering work in the development of the theory of portfolio choice, CAPM, and other fundamental contributions to the theory of corporate finance.

[31] "The Prize in Economics 1990 - Press Release". Nobelprize.org. 12 Dec 2011 http://www.nobelprize.org/nobel_prizes/economics/laureates/1990/press.html

[32] While each of the following risk factors will impact the pricing for both debt and equity, the impact will not necessarily be equal.

[33] The appropriate reference base rate for debt capital depends on several factors, such as the term and the repayment schedule of the loan.

[34] Less mature technologies, such as tidal, may have difficulty obtaining debt financing. Biomass projects will typically raise a lower amount of debt relative to other renewable technologies because of higher perceived operational risks, including the risk of obtaining a long-term fuel supply and the risk that project revenues become disconnected to project costs given swings in biomass costs.

project economic. [35] The components which influence the credit spread or risk component are detailed in Section 4.3.

This discussion of finance conditions for renewable generation facilities is in the context of the project finance approach which is used for most renewable generation facilities. Whatever mode of finance is used, the projects still must meet the rate of return criteria described here.

4.2 The Risk-free or Base Rate

The risk-free rate of return is a theoretical rate of return for an investment with zero risk of default in the region where the asset resides and forms the underlying basis for pricing the cost of equity and debt capital for a project since an investor will need to be compensated for each additional risk factor layered onto the investment. [36]

A complex set of factors governs the movement of interest rates, including monetary and fiscal policy. The rate determined at the federal and global level and fluctuations in the risk-free rate are largely outside of the control of the project developer. As shown in the graph below, the yield of the benchmark 10-year Government of Canada (GOC) bond has fluctuated from a high of 5.8% to approximately 2.0% between March 2002 and November 2011. During this time period, reference bond yields have been very volatile, which would have increased the cost of capital for renewable energy projects as prudent developers will leave a buffer to account for market changes in the key components of the cost of capital to improve the likelihood that the project will remain economically viable at financial close.[37]

[35] The cost of equity for a project should exceed the cost of debt for the project as debt receives a return on and of its capital in priority to equity capital, and has prior claim in the event of default. The effective cost of debt is also cheaper because of the deductibility of interest expense.

[36] In Canada, the yield from the 10-year government of Canada bond is commonly used as a proxy for the risk free rate for the purposes of estimating the cost of equity.

[37] Large developers are not as sensitive to the impact of volatility in base rates (and the other factors impacting pricing detailed in this section) as those developers have the ability to take a longer-term view of the financing markets. These developers can ***choose*** to finance the project on balance sheet on the assumption that financing rates will improve over time, at which point the developer can choose to replace corporate funding with project financing. However, large developers which choose to rely on corporate level or balance sheet financing to fund projects are more susceptible to changes in market conditions once their corporate borrowing capacity is reached. Calpine Corp. and Babcock & Brown are examples of large-scale bankruptcies for infrastructure companies with high levels of corporate level debt. The current instability in the European banking sector means that many of the European power developers are re-examining their corporate-level credit capacities which could curtail their ability to balance sheet finance going forward. See Chapter 5 for a more detailed description of the capital markets.

Figure 3: Canadian 10-year GOC Bond Yield

Data Source: Bloomberg

For debt capital, the reference rate varies according to the type of debt (floating rate or fixed rate), term and amortization schedule. While only a graph of the 10-year GOC bond yield was shown, the decline in yields and the high volatility (particularly since 2008) would be consistent across all reference rates.

4.3 Review of Key Risks that Affect Project Financing

The preceding discussion reviewed the economic and financial market fundamentals that determine the cost of capital for projects. To evaluate the challenges in the financing of renewable energy projects in Atlantic Canada it is important to understand project risks that will be considered by lenders and investors and the risks that are borne by developers to get their projects to a point where they can be financed. The risks considered by lenders and investors affect the terms under which IPPs will be able to secure financing, with riskier projects incurring higher costs of capital and projects with risks that are too great in the eyes of lenders and investors unable to attract the necessary capital.

4.3.1 Project Related Risks

This section reviews the project-related risks that affect the renewable project's cost of capital or affect its availability of capital. Six fundamental project-related risks affect the capital costs for projects:

1) technology risk, focusing in particular on the degree to which the technology is immature and doesn't have significant commercial operating experience for the proposed application;
2) operating risks including the operating performance of the equipment with respect to the energy conversion efficiency (e.g., power curve for wind) and fixed and variable operating and maintenance costs;
3) market risks, which consider the revenue uncertainty of the value of the project output;
4) resource availability risks, which consider the underlying variability of the resource and the potential for measurement error when estimating the resource;
5) construction risks that are borne by the project proponent rather than allocated to the firm procuring equipment for and constructing the project; and
6) market access risks including the potential for transmission constraints.

Each of these risks and the manner in which they affect the cost of capital is reviewed further below.

Technology and Operating Risks

Technology and operating risks are directly related. To more clearly distinguish between the factors that contribute to these risks we discuss them separately in this section. However, there is considerable overlap. Lenders are very reluctant to consider projects that have significant technology risk. At a minimum, they will look to the equipment vendor to provide performance guarantees and will want to ensure that the equipment vendor has sufficient financial capability to deliver on these commitments.[38] For example, for wind projects the equipment vendor typically provides a power curve guarantee which guarantees the project output levels at measured wind speeds.[39]

Many equipment vendors (virtually all wind turbine suppliers) offer service and maintenance agreements for the initial years of project operation, e.g., two to five years. For a set fee the

[38] The number of notable case studies where the supplier did not have such financial stability includes Clipper Wind Power which developed a 2.5 MW variable speed wind turbine and was led by seasoned wind industry professionals and AAER Inc., a Quebec wind turbine manufacturer. Clipper Wind Power's 2.5 MW Liberty Wind Turbines developed issues with the gear box and blades which resulted in a dramatic slowdown in orders and ultimately caused United Technologies to take a 49.5% interest in the Company and eventually acquire the entire company. AAER Inc. suffered from slow sales and eventually was acquired by Pioneer Power Solutions who discontinued the business.

[39] Specifically, the project owner receives liquidated damages to the degree that the project output is less than the guarantee. However, these liquidated damages are capped (often to 10% of the contract amount) and the project owner must demonstrate that the project output is less than promised. This requires a formal test, the cost of which would be paid by the project owner if it shows that the project output is consistent with the guarantee.

equipment vendor agrees to provide major maintenance services. This significantly reduces project operating risks by fixing maintenance costs according to the contract and ensuring that the maintenance is performed according to manufacturer's recommendations. In addition, it reduces the potential for disconnects between the warranty provisions in equipment supply contracts and maintenance contracts given that effectively one party will be providing the two services.

Another technology/operating risk is the equipment availability. For mature technologies this is a relatively minor risk, particularly for wind projects which install a number of wind turbines which effectively diversifies this risk. Hydroelectric turbines are also a mature technology with low performance risks. Once again, lenders will be reluctant to lend to projects that employ new technologies or equipment venders with limited operating experience.[40]

Atlantic Canada has a tidal resource that both Nova Scotia and New Brunswick want to develop. In Nova Scotia, two tidal array projects have received COMFIT contracts. This is a very new technology and these projects would represent its early deployment. An early application of this technology in Nova Scotia was removed from service after several months of operation. Lenders can be expected to perceive the technology risks of these projects to be very high.

A technology risk that can affect the cost of capital is that the useful life of the equipment could be less than anticipated, particularly if it were less than the tenor of the debt and the debt amortization period. A related risk is that required capital additions could be much higher than anticipated.

Market Risks

In the current financing environment lenders and investors are reluctant to finance projects which don't have a long-term power purchase agreement (PPA) which provides revenue certainty for project output. Without a PPA, the project proponent faces the risks of uncertain future revenues. The interconnected provinces of Atlantic Canada have wholesale market access which allows project proponents to wheel power to adjacent markets, but limited retail market access.[41] Therefore, independent power producers must be awarded a PPA or wheel power to New England. Ideally, the term of the PPA is as long as the debt term plus an additional two years or more, i.e., a two year or more tail that provides revenue certainty beyond the term of the debt and could allow the debt to be rescheduled if necessary. PPAs typically have durations of 20 to 25 years for wind and most renewable energy technologies and up to 40 years for hydroelectric projects.

[40] The introduction of new power generation technologies will frequently require government support to move from pilot-scale to utility-scale projects. In the US, the Department of Energy provided a Loan Guarantee Program (Section 1705), which facilitated the introduction of solar thermal generation projects in the U.S. Indeed, with the expiry of the program many of these solar thermal generation projects have been cancelled or are in the process of being converted into solar PV projects, which are better understood by the financial markets. Following the example in the US, Atlantic Provinces could encourage the development of innovative technologies that are well suited to the region (e.g., tidal technology) by providing support through a loan guarantee.

[41] Nova Scotia allows renewable project developers to have direct retail access.

Resource Availability Risk

Resource availability risk considers the underlying variability of the resource and the potential for measurement error when estimating the resource. This risk is most significant for wind projects given that relatively small variations in average wind speeds can have significant impacts on project output.[42] For example, wind resource forecasts rely on models which estimate a power output for each turbine at specific heights and locations within the project site, based on wind measurements received from the met towers which are in different locations and heights. For wind projects, resource availability risk is evaluated and mitigated in project financings by engaging an independent meteorological expert to review the wind resource studies and calculate the output that the project is likely to achieve or exceed at different probability levels, e.g., P50, P90, and P99.[43] For example, lenders will typically assess the adequacy of debt service coverage ratios (DSCR) at less favourable (more stringent) project output probabilities such as P90 and may require that the DSCR be at least 1.2 under the P90 conditions.[44]

For hydroelectric projects, lenders would expect good history of hydrological data, again converted into probabilities for different exceedance levels.

For biomass projects, the resource availability risk focuses on the ability of the project to secure sufficient long-term biomass supply at a consistent quantity and quality to ensure production. If the biomass is waste from another operation, particularly forestry, the renewable electricity generation project is vulnerable to loss of resource if the operation is shut down, even if it is a temporary shutdown. If the biomass is from other resources, the risk is the exhaustion of the resource in nearby locations and consequently higher transportation costs.

Construction Risks

Many IPPs rely on Engineering Procurement and Construction (EPC) contracts to manage construction risks. Under EPC contracts the IPP is able to allocate many of the construction risks and equipment cost risks to the firm providing the services. However, the terms and form of EPC contracts vary. Under a fully reimbursable EPC, the IPP maintains flexibility and bears most of the procurement and construction risk as costs are largely a pass through. Under a Lump Sum EPC, these risks are largely borne by the EPC firm, but the IPP pays a premium for this service and under some conditions (periods of significant expected cost escalation) such a contract is difficult to get. As implied, IPPs typically don’t have a comprehensive EPC and there are often multiple contractors, with one party assembling and erecting the wind turbines and another the balance of plant. Therefore, there is likely to be some residual risk to the degree that the contracts don’t link up. Finally, smaller community projects are unlikely to be able to secure such contracts given the size of the project, limited project budget, and limited interest of

[42] A rule of thumb is that a doubling of the average wind speed results in eight times more output.
[43] For example, the project output at P90 is the output that the project will achieve or exceed with a 90% probability. The output levels for different exceedance levels (e.g., P50 or P90) typically increase when assessed over a longer period of time (e.g., at P90 the annual output for a turbine may be 5,000 MWh and 5,250 MWh over 20 years.)
[44] DSCR are the annual Earnings Before Interest Taxes Depreciation and Amortization (EBITDA) divided by the annual debt service (interest and principal payments).

engineering and construction firms in performing the detailed work required to firm up pricing. However, unless the project site is difficult to access or requires significant groundwork, wind and solar renewable projects are generally easier to construct as the less predictable balance of plant costs represents a smaller proportion of the total construction budget (compared to traditional thermal projects).

Market Access Risks

All the Atlantic Canada provinces, except Newfoundland and Labrador (and Newfoundland isn't currently directly connected to the Eastern Interconnect), offer wholesale market access under Open Access Transmission Tariffs. The most significant market access risks for renewable IPP projects in Atlantic Canada are the potential for transmission constraints that cause the project to be constrained down or off. This risk increases as the penetration of intermittent renewable energy projects in these markets increases. [45] A critical determinant of the magnitude of this risk is the transmission service for which the IPP contracts and how this risk is addressed in the PPA. When a generator is provided with firm transmission service, curtailment risk is typically more limited, but this can require that the transmission network be reinforced, most likely at the cost of all transmission customers. If the IPP elects non-firm service it would be at greater risk of being curtailed if there were transmission congestion. A critical issue in Atlantic Canada is that the rules for managing transmission congestion (who would be curtailed and for how long) are not well developed. Furthermore, to date there have been relatively limited amounts of intermittent generation curtailed. Given both these factors it is difficult for IPPs to assess this risk.

Another market access risk that IPPs have to manage is the uncertainty associated with interconnection costs that they will have to bear. Most Generation Interconnection Procedures provide for a series of increasingly rigorous cost estimates. Typically, IPPs are awarded contracts before the final more detailed cost estimates are completed and there is risk that these interconnection costs estimates increase after the contract price has been established.

Development and Pre-Financial Close risks

A number of development related risks are addressed prior to project achieving financial close and therefore would not affect the cost or availability of capital. These risks typically determine project attrition rates. This includes environmental permitting risks and various financial and economic risks.

Financial and Economic Risks

IPPs also face financing risks associated with changes in financial market conditions during the period from finalization and acceptance of a contract pricing proposal until the project is financed. These financial and economic risks include foreign exchange rate variability where significant changes in foreign exchange rates (e.g., depreciation of the Canadian dollar) can increase the effective cost of equipment contracts that are priced in a foreign currency (US$ or Euros). This risk is mitigated to the degree that projects in Atlantic Canada purchase generation

[45] This risk is more of a concern in Nova Scotia given its transmission infrastructure and the location of considerable amounts of generation on Cape Breton with its major load centre in the metro Halifax area.

technologies with significant Canadian content or offering appropriate price escalators. Another financial risk is significant increases in interest rates and investor return expectations after proposal pricing has been finalized such as occurred in Nova Scotia after its 2007 Renewable Energy RFP. As discussed, these contributed to delays in the development of a number of projects and caused the ownership of several projects to change.

4.4 Limited Availability of Lenders and Equity Investors for Smaller Projects

In discussions with debt and equity capital providers, there was a common comment that it is difficult to provide non-recourse asset level financing for projects less than $50 million in size.

4.4.1 Fixed Costs of Due Diligence and Structuring

The due diligence and structuring costs for a typical renewable power project financing can easily reach $1 to $2 million in total transaction costs, and a significant portion of the transaction costs is fixed regardless of the size of the project. Examples of these fixed costs include the

- legal costs of the investor and the debt provider;
- independent engineer's report to review the initial cost and performance estimates for the project and review the ongoing capital draw-down requests for the lenders;
- resource assessment;
- environmental review;
- interconnection review; and
- financing and advisory fees.[46]

Projects that do not have the requisite due diligence will be unable to obtain project financing, and would require additional credit support from a third party source (equity provider, other assets or the government) to finance the project.

4.4.2 Greater Profitability of Larger Projects

Most of the capital providers with renewable project financing expertise are large institutions and need to pursue larger projects to provide a meaningful impact on financial results. Smaller financial institutions would generally not be capable of executing enough renewable power projects to develop an appropriate level of expertise. In speaking to financial institutions, project financiers typically have a minimum size threshold of $50 million for pre-existing relationships with a $75 to $100 million minimum threshold for most projects.

4.4.3 Developers Pursuing Smaller Projects Typically Lack Experience

The size of project the developers are pursuing is generally a good indicator of the level of experience a developer has, as an experienced developer would pursue larger opportunities as the pursuit costs are largely fixed and the economic payback to the developer is greater. Smaller

[46] While financing and advisory fees vary with the size of the project, the financing and advisory fees as a percentage of capital increase significantly for smaller projects to cover the fixed internal costs of providing these services.

projects have difficulty attracting capital and will suffer from lower returns unless the PPA price offers a sufficiently high premium over the PPA price for larger "utility-scale" projects.

4.4.4 General Illiquidity of Smaller Transaction Sizes

Capital providers that may not hold the investment to the end of its term place a premium on the ability to sell and trade the investment. Transactions below a certain size will also limit the universe of potential buyers for the investment and as a result increase pricing.[47]

4.5 Process for Administering RFPs

Pursuing power project development is inherently a risky process, and project developers strongly prefer processes which are quick and clear and thus reduce the opportunities for a proposal to be rejected.[48]

4.5.1 Insufficient Certainty for Project Developers

The RFP should have transparent criteria for the evaluation and selection of proposals and ensure that the process has a level playing field for all participants.

4.5.2 Length of Time Pricing Proposal Needs to be Open

Reducing the amount of time a pricing proposal needs to be open reduces attrition because the project economics are less exposed to market risk (e.g., changes in construction and financing costs). Therefore, it is desirable to reduce the period between when bids are submitted and contracts are awarded.[49] In addition the cost of maintaining the pricing in a RFP response is a direct function of the "firmness" of the pricing proposal and the amount of time the pricing proposal needs to be firm. As the cost for maintaining the pricing proposal is generally "at-risk" capital for the project developer, the project developers are keen to minimize this amount. Having larger amounts of "at-risk" capital creates a bias for larger projects and larger developers who can absorb the increased costs or increases the risks of project defaults by small developers.

4.6 Power Purchase Agreement Terms Leading to Higher Attrition Rates

Lenders pay particular attention to the details of the following terms. While the PPA should be designed to ensure and incentivize the owner of the project to operate the facilities at a high performance level, setting the performance levels at an inappropriately high or onerous standard will increase the risk of default, or potentially make it impossible for the project to obtain financing. Examples of these terms are discussed below.

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[47] In the 2011 Ibbotson Risk Premia Over Time Report, which evaluates the cost of equity in the US over time, Ibbotson estimated an equity investor would need a 4.48% premium to invest in a company with a market capitalization <$235 million (10th decile), versus a company with a market capitalization between $773 and $1.2 billion (7th decile).

[48] Every small developer we spoke to preferred a FIT program, where available.

[49] Power Advisory is seeking to do this in Nova Scotia by requiring Proponents to submit bids and accept the PPA that is offered rather than allowing negotiation of the PPA after contract award. This also ensures that all proponents are bidding to the same PPA and ensures the same risk allocation across projects.

4.6.1 Termination Provisions for Non-Performance

Lenders pay close attention to any termination provisions as the termination of the PPA will cause the project to enter default, and likely into a situation with a low prospect of recovery as the value of the project is substantially determined by the value of the PPA. Given the resource variability for most forms of generation in the renewables sector, termination provisions relating to a level of power generation are generally set at a threshold which recognizes the resource variability as the operator has less control over the actual power produced (unlike an operator of a thermal facility). This is particularly relevant for earlier-stage technologies such as tidal power.

4.6.2 Appropriate Pricing Escalators (Initial and Ongoing)

The risk of project attrition for PPAs without initial pricing escalators increases with the length of time between the PPA award and the closing of financing. During this period, construction and financing costs can continue to fluctuate, and in periods of extreme volatility, a sharp increase in the construction and /or financing costs without a change in the PPA price could cause the projects to become uneconomic to pursue.[50] However, allowing contract prices to escalate prior to commercial operation increases risks to the buyer and suppliers are able to mitigate these risks by contracting with the equipment manufacturer and EPC firms.

In addition, having a pricing escalator for the PPA which tracks the costs of operating the facility is strongly preferred. For debt providers, this can allow the debt service coverage ratios to increase (rather than decrease) as the remaining PPA life (economic value) diminishes. However, debt service coverage ratios will only increase to the degree that the proportion of the project price that escalates with inflation is greater than the proportion of project costs escalating with inflation. For equity investors, an inflation protected investment is highly sought after.

4.6.3 Pricing Penalties

Capital providers generally prefer incentive-based performance mechanisms to pricing penalties to encourage performance levels. Introducing pricing penalties can erode the financial strength of the project when the project is already underperforming, thus increasing the risk of default and potentially causing the project to be unfinanceable if the risk of default is considered too high. Therefore, a critical issue is at what performance level such penalties take effect.

[50] Québec Wind RFPs are examples of projects needing additional economic incentives introduced after the initial PPA award in order to finance the projects.

5 Review of Current Capital Market Conditions

5.1 Atlantic Canada vs. Other Jurisdictions

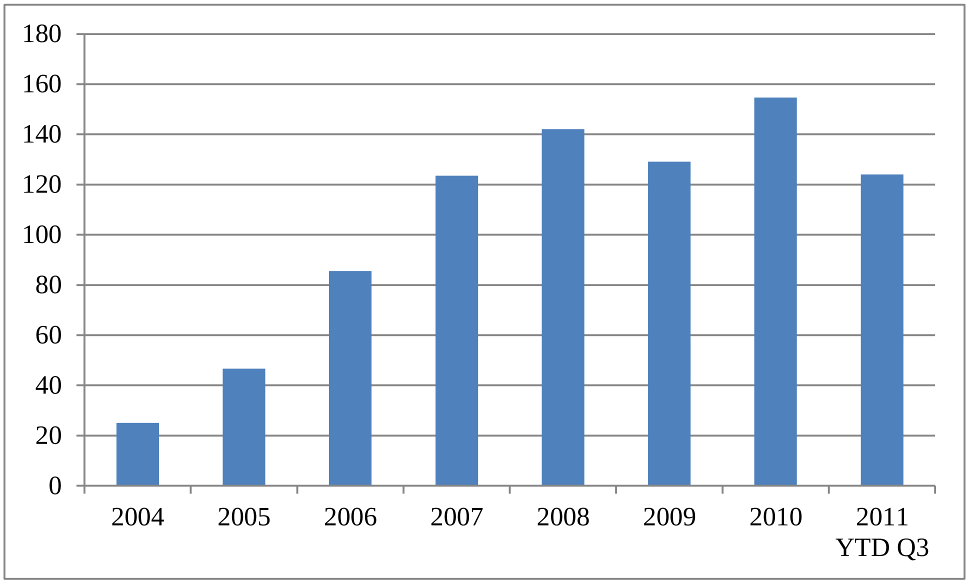
To evaluate the current capital market conditions for funding the construction of renewable power projects in Atlantic Canada, it is important to examine capital market conditions across Canada as much of the capital to build renewable power projects in Atlantic Canada comes from national and international investors.[51] While smaller projects, such as community-based projects, can be wholly funded by local capital or are unlikely to attract national or international capital, local investors would look to the risk and return profile for renewable projects located elsewhere in Canada as a benchmark.[52] However, the financing of smaller projects is more insulated from broader financial market conditions. The financing for these projects is likely to be influenced more by the availability of specific programs and policies that support their development and financing.

Our discussions with renewable sector investors made clear that the issues faced by projects in Atlantic Canada were similar to the issues faced in developing projects in other jurisdictions and that projects in Atlantic Canada did not require any adjustment in approach or debt or equity pricing. As such, this section focuses on the capital market conditions within Canada generally since we believe that cost and availability of capital for projects in Atlantic Canada is no different from that for other renewable projects of similar size located elsewhere in Canada.

Global investment in clean energy projects remains high as shown in Figure **4**. International investors continue to look favourably at investing in Canada due to the relative stability of the economy and relatively high growth rates. For example, Canada's forecast for GDP growth remained relatively robust at 2.3% in 2011 (compared to 1.4% for the G10 countries), and is expected to slow but remain relatively strong at 2.0% in 2012 (compared to 1.2% for the G10 countries).[53] Furthermore, the Canadian economy isn't subject to the same debt overhang as that plaguing the European Union and the U.S. which adds considerable uncertainty to their capital markets.

[51] Even projects wholly-owned by NSPI, a company located in Atlantic Canada, need to be evaluated in the context of the Canadian capital markets, as the majority of NSPI's debt and equity capital is from investors domiciled across Canada.
[52] Subject to a size-based premium, as discussed in the cost of capital Chapter 4.
[53] Bloomberg composite of economists, December 2011.

Figure 4: Global New Investment in Clean Energy (US$ Billions)[54]



Data source: Bloomberg

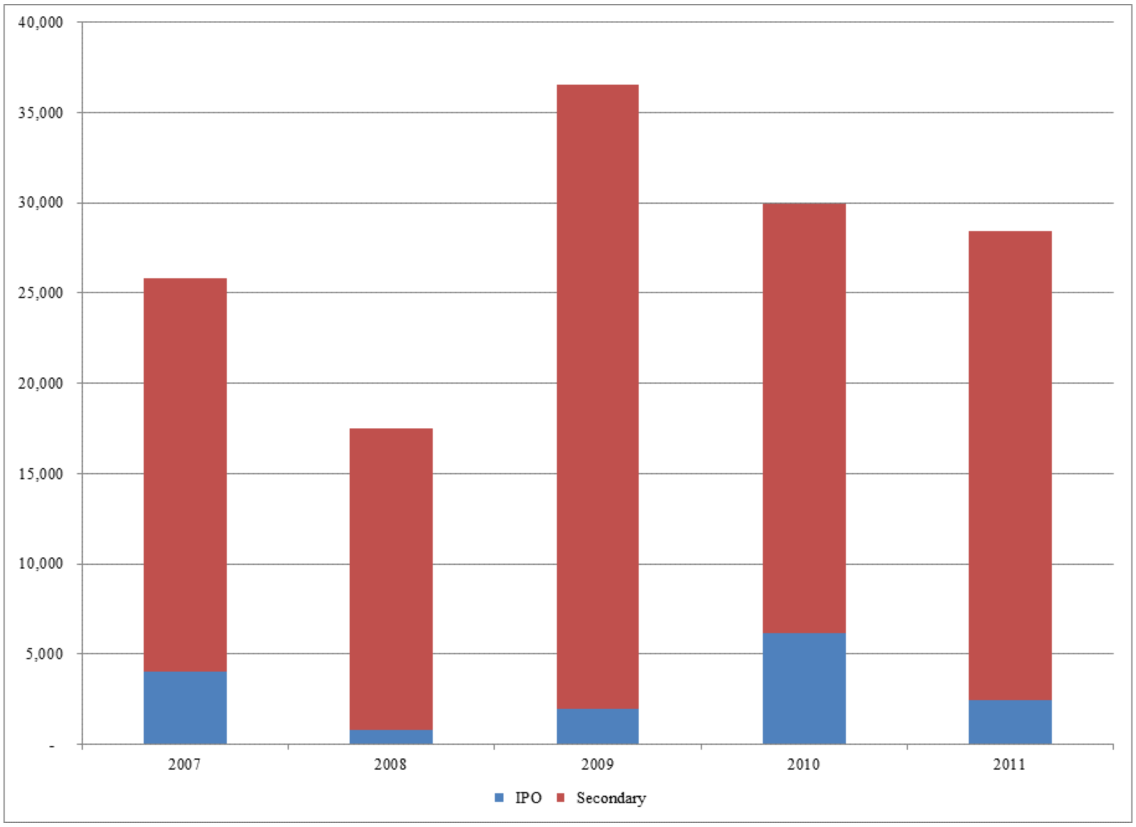
5.2 Equity Capital Markets

5.2.1 Availability of Capital

Ability to raise capital for safe, high-quality investments continues to be strong, while the continuing volatility in the equity markets makes raising capital for new ventures difficult. As shown in Figure 5, while the total amount of equity capital raised in Canada has recovered, raising capital for new companies (initial public offerings) remains a challenge.

[54] Source: Bloomberg New Energy Finance

Figure 5: Equity Capital Raised in Canada, Initial and Secondary Sales ('000s)



Data source: Bloomberg

For established project developers, raising capital has been relatively straightforward. This is demonstrated by the ability of Capstone Infrastructure , Innergex Renewable Energy , and Algonquin Power & Utilities Corp., three electricity generation and infrastructure companies with significant renewable project holdings, to easily raise equity capital on a bought-deal basis in 2011 to support acquisitions.[55] In addition, smaller project developers, which are generally thinly-capitalized or have a limited track record, got bigger in order to improve access to the capital markets and have the financial capacity (or buffer) to raise capital when it is advantageous to do so. Examples in 2011 include developers merging with other developers (Magma Energy's acquisition of Plutonic Power), with their affiliated operating portfolio (Innergex Renewable and Innergex Income Fund), or with a financial sponsor (such as Shear Wind with Inveravante).

Unlisted infrastructure sector funds have also invested in Atlantic Canada, and many infrastructure funds are looking for investments.[56] Thirty-eight infrastructure funds closed in 2011, raising a combined $16 billion and Prequin estimates that $34.3 billion is available for

[55] In a bought deal situation, the dealer will fully underwrite the offering. Therefore, the dealer takes the risk of what it will be able to sell shares for. A bought deal indicates that the dealer is highly confident of its ability to sell the shares without the benefit of pre-marketing intelligence. This is in contrast to a marketed deal where the dealer acts on a best-efforts basis.

[56] Firelight Infrastructure Partners has invested in Amherst wind farm and the Dalhousie Mountain wind energy project. Firelight Infrastructure Partners is a JV between OP Trust and Dundee Real Estate Asset Management with a mandate to invest in renewable energy projects across Canada.

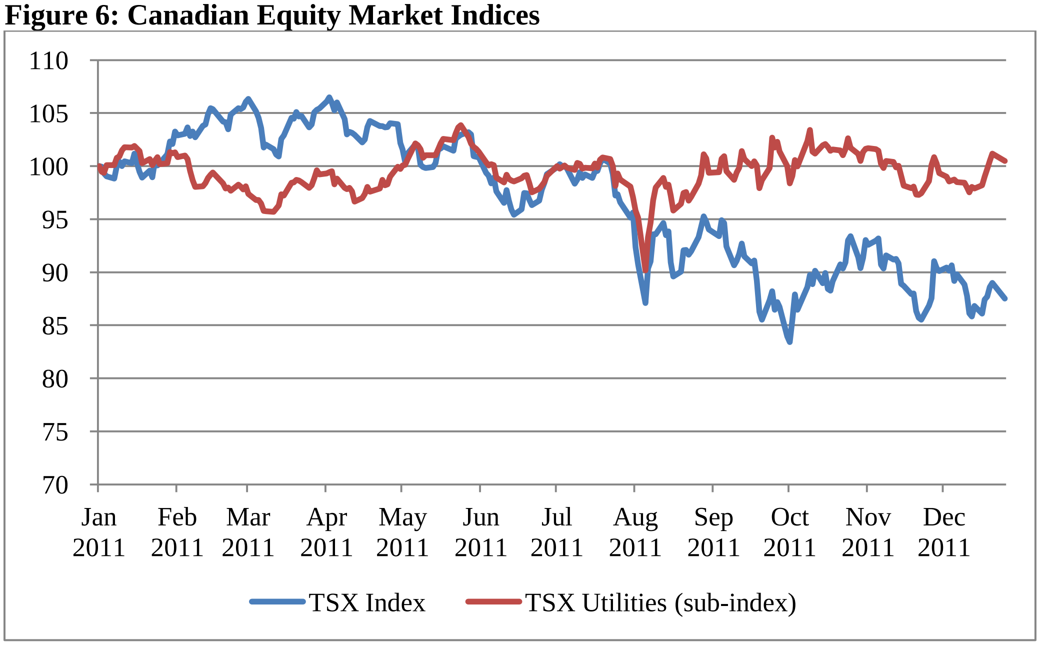
infrastructure investments by unlisted infrastructure investors that are targeting North America.[57,58]

5.2.2 Cost of Capital

The TSX utility (sub index) closed 2011 flat to 2010, while the broader TSX index closed down by 12%. The continuing volatility in the broader equity markets has caused investors to focus on safe, cash flow producing investments.

During 2011, Canadian publicly traded power companies with significant renewable power assets had a cost of equity of approximately 9.6% to 11.7%.[59] These publicly traded companies are a combination of operating and development assets. The cost of equity range is consistent with recent equity return expectations for operational assets which is below 10%, and for development assets which is generally in the mid-teens.[60] These observations are further supported by discussions with other infrastructure sector professionals regarding current valuation levels and the degree of competition for safe infrastructure investments, such as renewable energy projects which are underpinned with long-term power purchase agreements with counterparties with strong credit.

Figure 6: Canadian Equity Market Indices



Data source: Bloomberg

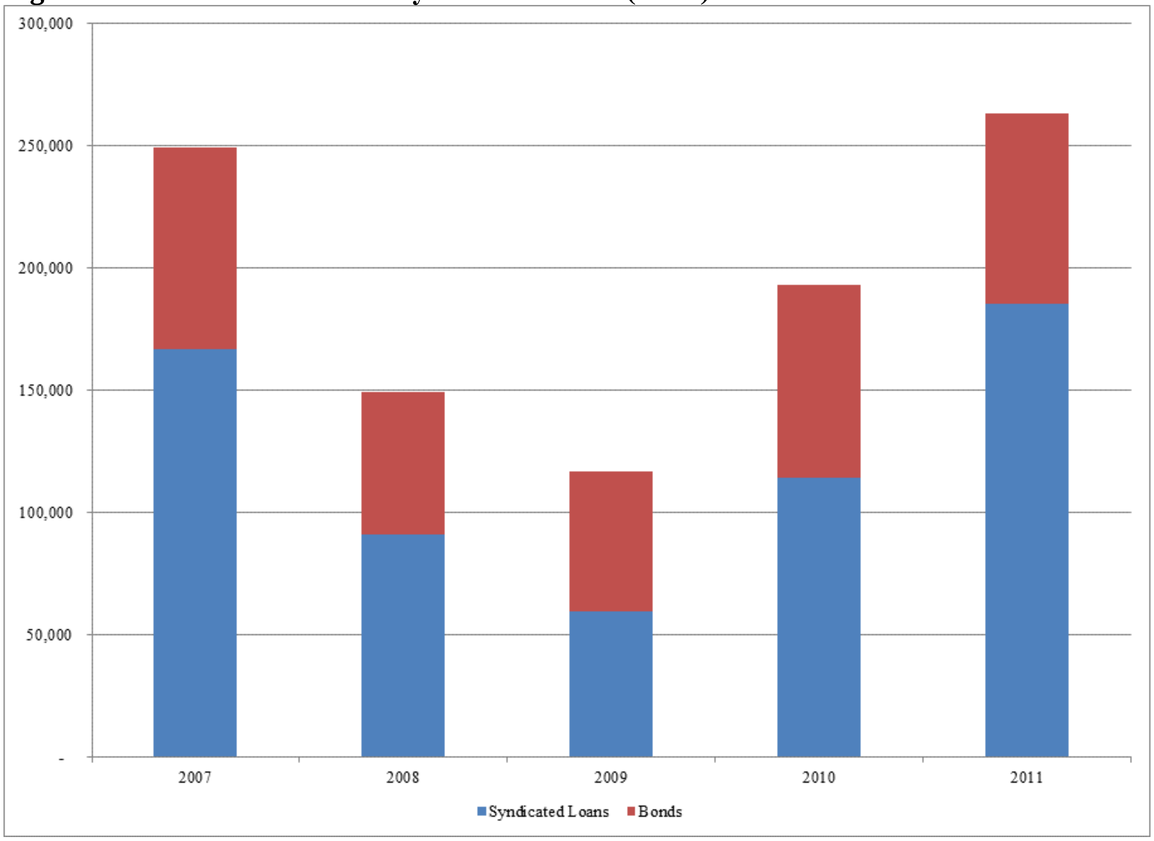
[57] Prequin quarterly infrastructure review, Q3 2011.
[58] "Infrastructure Ends 2011 on Fundraising High" (Press release). Prequin. January 4, 2012. http://www.preqin.com/docs/press/Infrastructure_2011.pdf
[59] The cost of equity capital for Northland, Capstone, Innergex, Brookfield, Algonquin, and TransAlta were estimated using CAPM on November 2, 2011. Source: Bloomberg
[60] Return expectations will vary according to the specifics of the assets. Return expectations will generally be higher for smaller projects.

5.3 Debt Capital Markets

5.3.1 Availability of Capital

Significant debt capital is available in the Canadian market and as shown in Figure 7 below, the value of bond and syndicated loan transactions completed in Canada in 2011 was at its highest level in the past five years and more than double the amount of debt capital raised in 2009.

Figure 7: Canadian Bonds and Syndicated Loans ('000s)



Data source: Bloomberg

For renewable project developers, there are two main types of project financing available: (i) a mini-perm structure which is a form of bridge financing which requires a refinancing with a term loan or a bond no later than five years post project completion; or (ii) a permanent term loan which provides a locked-in rate over the entire term of the loan.[61, 62] The choice between option (i) or (ii) depends on the depth of the each market at a given point in time, and also on the developers' assessment of the refinancing risk as the project will book a gain or loss on the difference between the assumed and actual refinancing spread at the time of refinancing.[63]

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[61] The refinancing period for the mini-perm will vary but is frequently for a period no more than five years.
[62] In a mini-perm facility the cost of the bridge loan increases each year post completion.
[63] The mini-perm market is much deeper in terms of the size of market and the number of participants. However, capital providers compete for quality projects and savvy developers continually evaluate and choose between all their sources of capital for each project.

Under a permanent term loan structure, the entire repayment schedule (principal and interest) is specified over the entire term (frequently 18-years post COD for a 20-year PPA). In a mini-perm structure, the amortization and frequently the base rate portion of the interest payment is set over the full term (the same 18-years post COD as in the term loan), and the developer must refinance the mini-perm with a new term loan at up to five years post project completion. If credit spread at the time of refinancing is lower than the assumption used to set the original mini-perm amortization schedule, then the developer will realize a release of equity; conversely if the credit spread is higher than expected, then the developers' dividends from the project will be reduced. A mini-perm structure is a bet by the developer than the credit spread will be below the assumed spread before the end of the mini-perm facility, and that the weighted-average interest rate is below what would otherwise be available under a permanent term loan structure.

Canadian and US banks will generally offer only a mini-perm structure, while life insurance companies and pensions funds offer fixed rate project debt financing over the entire term of the financing and may also decide to invest equity capital as well. Japanese and European banks traditionally have offered both mini-perm and long-term fixed rate project financing structures. While Japanese banks are still active in the Canadian market, many European banks have significantly curtailed their activities in Canada.[64, 65] As European banks were significant lenders to renewable energy projects globally, there should be an impact from these lenders leaving the market, but so far, there remains strong demand and available capital from the other industry participants.

Given the continuing volatility in Europe it is difficult to determine the number of active power project financing firms in Canada. However, at least 30 different institutions have successfully provided project financing debt to Canadian renewable projects since 2010.[66]

These specialized project finance lenders will not lend to smaller community projects as it would not meet their minimum size threshold ($30 to $50 million). For these lenders to lend to a

[64] Many of the prominent European lenders to the renewable sector are based in or have significant exposure to countries which have received or are considered at-risk of requiring a bail-out which would cause the value of their debt to be written down. The European Banking Authority in its latest round of stress tests dated December 8, 2011, estimates that the European banks have a shortfall of €115 billion including sovereign capital buffer. Many European banks have shut down or ceased their Canadian lending activities. At times, the decision to shut down has come abruptly, even while in the late stages of a transaction.

[65] Basel III, which will be phased in from January 1, 2013 to January 1, 2019, provides for a set of comprehensive reform measures designed to strengthen the regulation, supervision and risk management of the banking sector. The regulations are generally expected to increase the cost of financing as banks will have higher capital requirements (and thus have less ability to lend or generate revenue on the same capital base). The regulations also encourage banks to have a closer match between the maturities of a bank's assets and liabilities. As the majority of the banks' liabilities are on a short-term basis, it's believed that a bank's capacity to offer long-term project financings will be become more limited and result in more mini-perm financings.

[66] This is based on the review of the public disclosure for sixteen renewable power projects with financial close announced in 2010 and 2011. Canadian and US Banks: CIBC, BMO, TD, BNS, National Bank, Union Bank; Life insurance companies: Manulife and the other major life insurance companies; Funds and Pension Funds: All major Canadian pension funds, such as Caisse de Depot, Stonebridge; Japanese Banks: Bank of Tokyo, Sumitomo, Mizuho, SMBC; European Banks: Deutsche Bank, KFW, Landesbank, Siemens, Naxitis, Rabobank, BLB, Bilbao, Dexia, Nord L/B, Caixanova, and WestLB.

community project, the community projects would need to be aggregated to meet the minimum size threshold.[67]

5.3.2 Cost of Capital

The current all-in cost of debt for A and BBB rated 10-year loans is at a 5-year low, despite credit spreads which have remained in line with credits spreads from 2009/2010.[68] The continued decline in base rates has caused the decline in financing costs as pricing and other debt terms have largely remained the same:

- Debt / capitalization: ~75%[69]
- Amortization term: 18-years (assuming a 20-year PPA)
- DSCR (minimum): 1.20x – 1.25x
- Short-Term Rates: ~1.5% (6 month Canadian LIBOR)[70]
- Swapped Rates: ~3.0%[71]
- Credit Spread: 225 - 250 bps[72]
- All-in Rates: 5.25% to 5.50%

Base rates are expected to remain low as the Bank of Canada has kept and is expected to continue to keep overnight lending rates at 1.0% until the end of 2012.[73] Going forward, there should be upward pressure on credit spreads for renewable projects as many European renewable power sector lenders have exited the Canadian markets pending the resolution of the sovereign debt situation in Europe.[74] So far we understand that credit spreads for renewable projects in Canada

[67] There have been government sponsored programs, such as PEI Energy Savings Bonds, which were designed to allow Islanders to invest in the Eastern Kings Wind Farm. However, unlike the project financings discussed in this report where debt investors have recourse only to the project assets, the PEI Energy Savings Bonds are fully guaranteed by the Province of PEI and thus the repayment risk for the debt investors is not dependent on the performance of the wind farm and thus avoids the requirement for due diligence and structuring costs on the part of the investors. Approximately \$6 to \$7 million was raised under this program.

[68] A credit spread is the difference in the all-in interest rate and the corresponding rate on the "risk-less" benchmark security. The credit spread is primarily meant to compensate the investor for the incremental risk of default above and beyond the default risk in the benchmark security. For floating-rate debt, the credit spread may be over a benchmark interest rate such as LIBOR (London Interbank Offered Rate), Bankers' Acceptances or Prime rates. For fixed rate debt, the credit spread would be over the yield for a Bank of Canada bond (treasury security) with the same term.

[69] Subject to achieving the debt service coverage ratios (DSCRs) indicated.

[70] This will vary depending on reference base rate used by the bank

[71] The lender will likely require a portion of the base rate to be fixed over the amortization period of the loan. The swapped rate is the rate the project will pay the swap provider in exchange for receiving the floating rate over the period. The actual swap rate will depend on the credit quality of the project and the actual cash flow profile of the project.

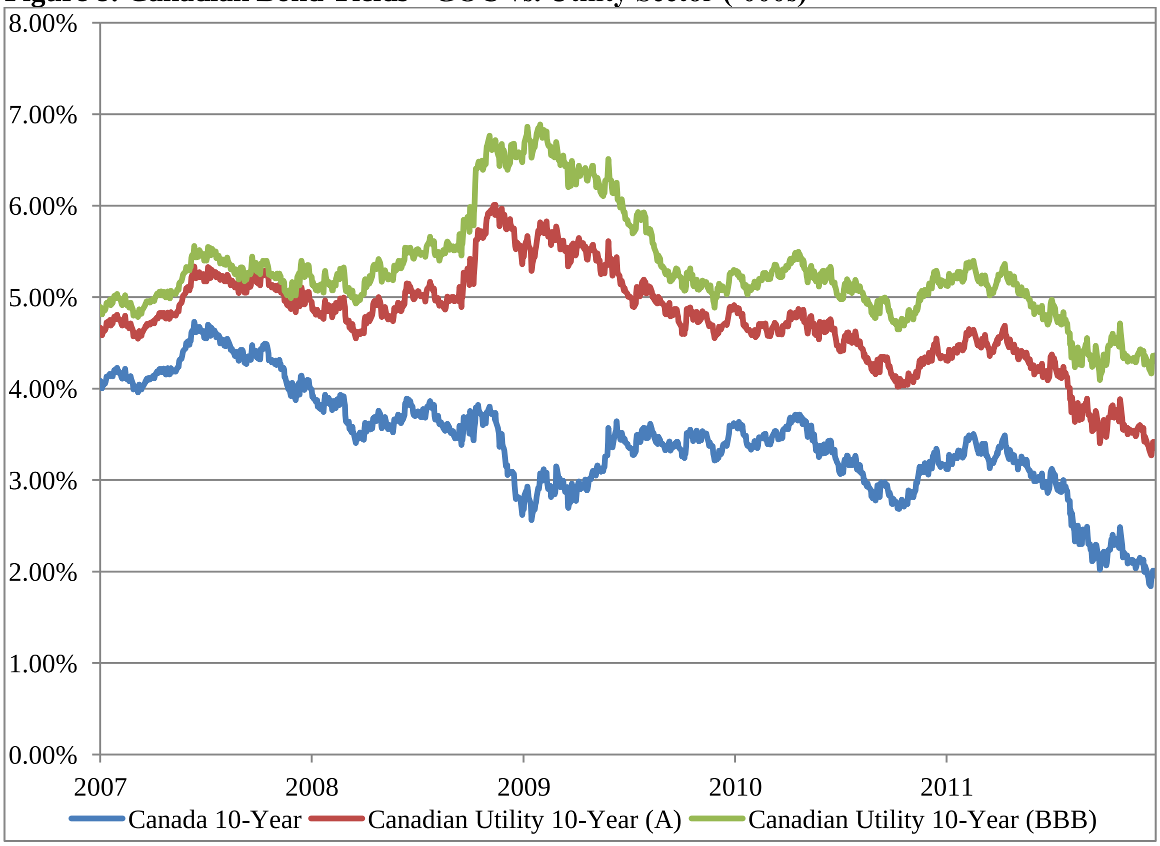
[72] The credit spread is quoted on a floating rate basis, typically a reference benchmark such as LIBOR, BAs, or Prime

[73] The Bank of Canada currently maintains overnight lending of 1.0%, which is very low on a historic basis (for comparison, the overnight lending rate was 4.25% in 2007). Economists expect the Bank of Canada to maintain the 1.0% rate in 2012.

[74] In discussions with other project financiers, many European banks have shut down or ceased their Canadian or North American project finance lending activities. At times, the decision to shut down was made even while in the late-stages of a transaction or a secondary sale of the debt to another lender

have not been adversely impacted as there remains strong demand among debt investors for infrastructure sector debt.

Figure 8: Canadian Bond Yields - GOC vs. Utility Sector ('000s)



Data source: Bloomberg

5.4 Conclusions

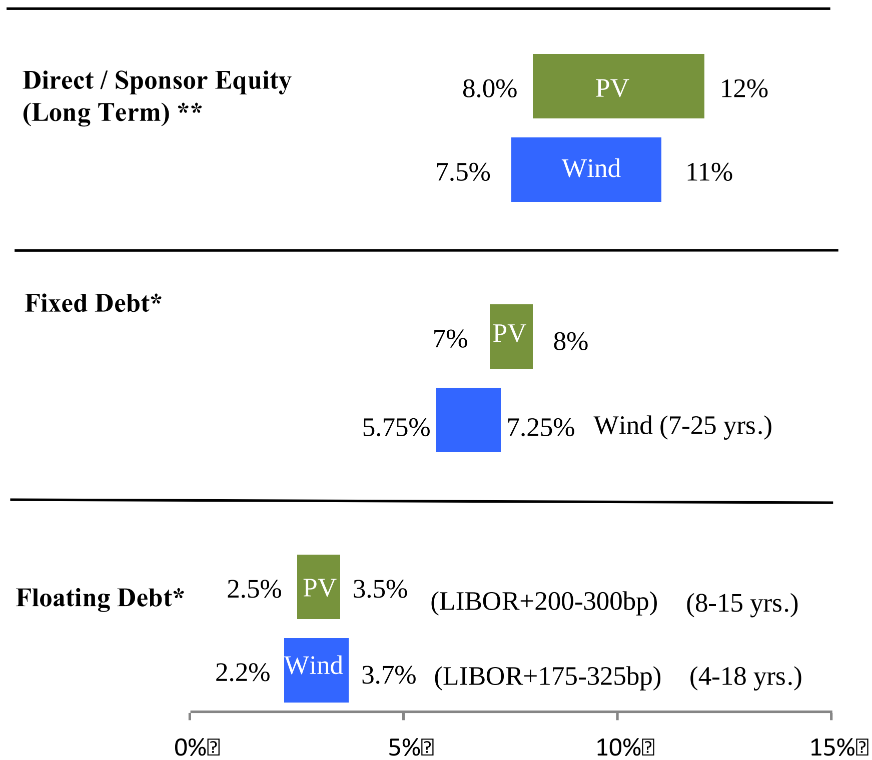
There does not appear to be any general impediment to raising capital for utility-scale renewable power projects in Atlantic Canada. While the market remains volatile and could change quickly, there is demonstrated interest and capital available from lenders and equity investors for utility-scale renewable power projects developed by IPPs.

Figure 9 summarizes the required equity after tax returns and cost of debt for wind and solar PV projects financed in the U.S. While the U.S. and Canadian capital markets are highly integrated, there can be differences in required underlying returns given differences in inflation expectations, monetary policy, and resulting investor expectations regarding exchange rates, and the use of more complicated tax structures. Given these differences, Figure 9 is presented because it represents a comprehensive review of the required return on equities and costs of debt. The greater spread for equity returns reflects that equity is paid after debt and is inherently more risky. The lower band for equity is associated with larger projects with higher-quality cash flows using

immediately after closing. Several European banks are reportedly in the market selling their entire renewable project finance portfolios.

proven technologies which can attract numerous equity investors who must compete to participate and the higher band is for smaller projects or those using nascent technologies with higher investor risk given limited operating performance or a lower-quality cash flow profile.

Figure 9: Estimates of Current Debt and Equity Terms



*Debt has an upfront fee of 200-275bp.
**Equity returns are after-tax.

Source: Mintz Levin

6 Financing Options for Atlantic Canada

The preceding analysis and discussion indicates that there aren't unique challenges to financing renewable projects in Atlantic Canada. The primary challenges that renewable energy projects in Atlantic Canada face are similar to those present in other markets, with the most significant faced by smaller renewable energy projects developed by community or aboriginal groups. Given the economies of scale associated with financing renewable energy projects and the more limited financial resources of these groups, they face distinct challenges.

The following section presents a series of case studies, the first of which focuses on the financing of a large wind project and represents a relatively typical project finance approach which is commonly used to finance large renewable energy projects. The subsequent case studies review different programs and entities that have been established to help aboriginal and community groups overcome the barriers to financing smaller renewable energy projects. These case studies represent models that could be employed in Atlantic Canada.

6.1 Large Wind: Shear Wind

Purpose of Case Study

This case study considers Shear Wind, a local developer based in Atlantic Canada which was able to secure funds to build the $150 million, 62.1 MW Glen Dhu project located in Nova Scotia. Shear Wind is an example of a local developer's journey to secure development and project capital to build utility-scale renewable projects while remaining independent. The project reached commercial operation on March 31, 2011.

The Finance Model

Initial Stages
Shear Wind initially incorporated on December 17, 2004 with a focus on developing wind projects, primarily in Nova Scotia. Shear Wind's initial projects were joint-venture agreements with Renewable Energy Resources Ltd. (RESL), and Shear Wind was able to raise $6.1 million through three private placements of flow-through and regular Class A common shares to fund the purchase of six turbines and pursue the development of a portfolio of potential 50 to 100 MW wind sites in Nova Scotia.

In 2006, Shear Wind amalgamated with MWP Capital, a capital pool company (CPC)[75], to become a public company on the TSX. The new pro-forma company had $2.6 million of cash remaining on hand.

Development Costs
On August 30, 2007, Shear Wind submitted a proposal to Nova Scotia Power to construct the Glen Dhu project, and spent approximately $500,000 on the initial bid submission and expected

[75] A CPC is a publicly-listed, limited blind pool formed for the purposes of identifying and acquiring a business. The amalgamation of the blind pool and the target business is a qualifying transaction.

to incur an additional $500,000 in costs to bring the project to a construction ready stage. The initial 20 MW of the project was anticipated to be in-service by November 30, 2009.

However, Shear Wind was unable to secure the requisite financing due to the severe turmoil in the world financial markets between 2007 and 2009. Shear Wind incurred a $500,000 penalty for not having the first 20 MW of generation up and running by November 30, 2009 and incurred additional carrying costs to maintain the $2.7 million of deposits for the performance security and interconnection studies for the Glen Dhu facility.[76]

Securing Project Capital

However, the strengthening of the Canadian dollar against the Euro caused the project to become economic and the initial cost estimate of $270 million for a 55 MW project declined to an actual project cost of $150 million for the 62.1 MW project. On November 3rd, 2009, Shear Wind closed a private placement for $26.9 million from Inveravante Inversiones Universales, S.L. (Inveravante), a Spanish utility conglomerate with an international portfolio of wind projects. Upon closing of the private placement, Inveravante would own 62% of the common shares of Shear Wind on a fully-diluted basis, and on June 25, 2010, Shear Wind secured the additional equity funds required to build the 62.1 MW Glen Dhu project by selling a 49% interest in the project to Inveravante in exchange for $22 million. Securing these funds allowed Shear Wind to place deposits on the turbines ($24 million) and begin construction.

Project Details

- Capacity: 62.1 MW (27 Enercon E-82 2.3 MW turbines)
- Location: East of New Glasgow, Nova Scotia
- Total Capital Cost: $150 million
- Senior Debt Financing: $114.5 million (78%)
  - Construction Financing $107 million
    - 18 year term
  - $1.5 million LCs to NS Power
  - $6.0 million LCs for the debt reserve
- Equity Financing: $35 million (22%)
  - $32.9 million equity
  - $2.1 million subordinated loan by Inveravante
- The loan is secured by a first priority lien on substantially all of the assets of GDWE LP, the JV partnership between Shear Wind and Inveravante which owns the project company
- The lenders are Banco Bilbao Vizcaya Argentaria SA (BBVA) and Instituto de Credito Oficial (ICO)

[76] During this time period, some of Shear Wind's peers sold their projects or development companies to well-capitalized partners, and these partners were able to balance sheet finance the start of these projects despite volatile market conditions.

Summary
Shear Wind's Glen Dhu project is an example of a successful utility-scale wind development. Despite Shear Wind's efforts to remain wholly independent, the case study demonstrates that large-scale power development is expensive and difficult, and typically requires partnership or backing of a large, well-capitalized partner for a utility-scale project.

6.2 Cooperative: Water Power Group

This case study describes the approach being employed by a company in Ontario which has developed an alternative financing model for small renewable energy projects that does not require separate project assessments by lenders and does not require finding equity sources for each project.

The Water Power Group, as its name implies, is focused on developing and owning small hydroelectric sites in Ontario. These hydroelectric projects will be financed by forming unincorporated joint ventures that will obtain the equity and long-term debt for each project. Up to 49% equity is to be offered to community or aboriginal groups and by so doing qualifies for higher power purchase rates under the Ontario Power Authority's (OPA's) FIT program. The remaining project equity would be provided by the Water Power Group Limited Partnership. The Water Power Group has received a term sheet, subject to due diligence, for 40-year debt under favourable terms with up to 85% coverage which would be made available to these projects.

The model rests on four legs:

1) Use of local cooperative or joint venture capital for the equity portion of the investment. The cooperative is established to secure equity from interested stakeholders in the local community, which could include the municipality itself or individuals in the community. Under the cooperative structure participants will benefit from the diversity provided by investing in multiple projects.
2) Establishment of an overall cooperative structure within which to bundle each project. This allows debt finance for the individual projects to come under the broader umbrella so that each project does not require separate negotiations over the terms of the loans.
3) Replication of project types (all small hydroelectric projects, from 0.5-5 MW) so that the company's expertise and the business model can be extended over more projects.
4) Favourable treatment accorded community and aboriginal projects under the OPA's FIT program and the various programs put in place by the OPA and Ontario Government to promote the development of community and aboriginal projects.

The company has been in existence for four years. They look for opportunities such as small projects within a community. They seek to utilize existing dams in which they can install low-impact turbines to generate electricity.

Then they approach the community to secure local support for the project and local interest in participating in the development. They first seek equity investors within the community or surrounding communities. If they find them, the project can be set up as a Joint Venture between the Water Power Group and the local investors. Water Power Group will also assist the local community with forming the joint venture or coop, and with raising the local equity. The projects are not dependent on raising local equity. Water Power Group's preference is that community equity be up to 25%; debt can be up to 85%, requiring only 15% equity, but the preference is for community equity to be at the top of its range, thereby reducing reliance on debt. The debt can come from insurance companies, for whom longer PPA durations and the guaranteed nature of cash flows from the buyer are favourable.

If there are not enough individual investors in the host community or surrounding ones, it would rely on equity from the limited partnership or use a cooperative structure for which it is seeking approval from the Financial Services Commission of Ontario. The cooperative structure allows many projects to fall under the financial umbrella of the overall cooperative entity, eliminating the need to raise funds individually for each of these small projects. In effect, this structure allows these projects to be bundled. The company has a line of term debt that they can access as needed.

The company suggests that this model can also work as a public-private partnership between them and the municipality. They bring the technical expertise that the local community lacks.

The small size of the projects requires such a financing structure. For projects of the size being considered, which range from $3 to $10 million, it would cost about $200 thousand to raise the necessary funds. The venture capital community was not interested because of the small size of these projects.

Community support and involvement are keys to this model. The company expects that the community support shortens approval time.

Not all projects using a cooperative structure have succeeded. For example, the Pukwis Energy Co-op, which was planning to build a 20 MW wind farm on Georgina Island in Lake Simcoe, Ontario, as a joint venture with the Chippewas of Georgina Island First Nation, has suspended operations, citing (in a brief press release) problems with finance as one of the reasons for the suspension.

Other Supporting Programs

Ontario has a number of programs to support community renewable projects. The Community Energy Partnerships Program (CEPP) is a grant program to support community power in Ontario and assists community power projects through funding of up to $200,000. Eligible expenses include site investigation, resource assessment, business planning, engineering studies, and studies needed for Renewable Energy Approval or other approvals. As CEPP Program Manager, the Community Power Fund provides education about the CEPP, helps people through the application process, prepares the initial screening of and recommendations regarding applications, and provides approved project monitoring. Within the Community Power Fund, the Investment Funds Platform includes Direct Investment Funds to maximize funding for community power across the full capital spectrum, and fund management and fiduciary services designed to harness and accelerate fundraising capacity at the local level. Since 2007, CP Fund consulted with a diverse range of community power project developers, and allocated $1.5 million to assist in the development of 25 renewable energy projects owned by Ontario-based community and aboriginal groups.

6.3 Master Financing Facility

One financing approach that is receiving increasing attention in the US is a Master Financing Facility under which a developer bundles various projects together to reduce transaction costs and the overall risk profile. Under such a financing facility, the financier agrees to finance every project that a developer puts in service between specific dates up to some dollar amount assuming that the projects satisfy specific criteria agreed to by the developer and financier. These criteria are likely to include the project capacity factor, cost, and credit quality of the buyer (recognizing that the developer might also being seeking to finance projects in other jurisdictions or with other buyers). Alternatively, the developer will have the projects under contract allowing the financier to have a high level of comfort regarding the specific projects.

Master Financing Facilities are often used in the US to finance portfolios of solar PV projects. A critical element to financing such projects is efficiently utilizing the significant tax benefits that they generate. With a 30% investment tax credit and accelerated depreciation, tax benefits are critical to the financing of such projects. These transactions are structured around leases where the lessor owns the projects for tax purposes and the lessee sells the electricity, and collects revenue, much of which it pays to the lessor as rent for the use of the equipment, with the residual representing operating profit.

The difficulty in applying bonus depreciation (Class 43) tax-driven financing structures in Canada (based on current regulations) is that the purchaser for the tax attribute must already be generating similar income (such as income in the generation sector) to apply the accelerated depreciation against, whereas in the US the tax credits and accelerated losses can be applied against any income.

Canadian renewable power projects can elect to receive Canadian Renewable and Conservation Expense (CRCE) credits, which can be used by third-party investors. The CRCE program was adapted from a program to allow oil and gas and mining companies to write off the upfront soft costs incurred in development. For projects in the renewable power sector, effective use of this credit artificially forces the development into two phases – a turbine phase which pays for a set of test turbines to be built, followed by an infill construction phase which occurs after the 120-day test period. CRCE tax investors fund the capital for the turbine phase and are eligible to claim the majority of their investment as deductions against income in the first year of investment, be carried forward indefinitely, or flow through to investors under a flow-through share agreement. The artificial delay in the construction period means that developers need to balance the delay in the construction schedule with the cost of funds CRCE financing provides. The majority of renewable projects in Canada are not funded in this manner, although small developers may use CRCE to finance their development efforts. Contrast this to the US market where tax-driven financing structures are necessary in order to achieve a competitive cost of capital for financing renewable projects

Financing structures which aggregate smaller structures under one master facility can certainly take advantage of economies of scale (financing, operations, due diligence, etc) to improve returns. The key to the success of such financing structures is the upfront planning and co-ordination required to ensure that the projects are structured identically and occur within a very close timeframe. Recall that this is a critical driver for the structure employed by the Water Power Group.

A summary of generic terms for a US rooftop solar portfolio is shown in the summary Table 3 below.

6.4 Government Loans Guarantee: Aboriginal Loan Guarantee Program

Purpose of Case Study
This case study describes a government-funded program which provides equity funding to specified groups for projects of electricity generation from renewable resources or for transmission facilities. In the case of the Aboriginal Loan Guarantee Program (ALGP), the specified groups are First Nations or Métis communities.

The Finance Model
The Ontario government established the ALGP in September, 2009 in accordance with a commitment in its budget. ALGP has a limit of $250 million in total loan guarantees to First Nations and Métis communities to fund up to 75% of their equity portion for participation in renewable energy or transmission projects. In essence, this equity becomes subordinated debt which is junior to the senior debt. There is a limit of $50 million in guarantees for any individual project.[77]

The government assigned administration of the program to the Ontario Financing Authority (OFA), an agency of the Ministry of Finance which is responsible for managing the investment of funds and financial risk for the province. The OFA also provides all of the resources for the Ontario Electricity Finance Corporation, the financial successor to Ontario Hydro. The OEFC inherited all of the former Ontario Hydro's stranded debt and also became the counterparty to its non-utility generator (NUG) contracts. Through its work on behalf of the OEFC, therefore, the OFA has experience with managing debt for electricity generation and with administering contracts for electricity generation.

When the ALGP was established, it was committed to extensive due diligence before guaranteeing any loans. For that purpose, the OFA has engaged a due diligence provider which is assisting the OFA with the due diligence review. Given the extensive due diligence that is performed, the OFA is only able to evaluate three to four projects per year. Some parties have commented that the due diligence performed is equivalent to that for securing a bank loan; the OFA believes this to be appropriate given the significance of the financial commitments and the potential commitment of public funds. OFA also noted that banks can lean on the ALGP due

[77] OFA staff indicated that in Ontario loan guarantees aren't shown as a financial obligation, but are treated as a contingent liability that doesn't affect the Provinces' financial obligations unless there is a likelihood of default. These policies vary by jurisdiction. Furthermore, there is no loan loss reserve given the limited risk of default.

diligence and that this would reduce the burden on the project and proponent. Most projects are able to secure more favourable terms with lenders and the equity partners based on the technical support and expertise provided by the ALGP team. While there is a loan guarantee fee, it isn't based on cost recovery, but is expected to cover due diligence costs over the loan term. OFA suggested that a minimum project size limit would probably be appropriate given the significant due diligence resources devoted to evaluating each project.[78]

Only the Minister of Finance can commit the province financially, so the OFA's role is ultimately to make recommendations to the Minister.

The ALGP is in keeping with the Ontario government's commitment to promote the involvement of aboriginal communities in development of renewable energy in the province. Another incentive for such groups is that wind power and hydroelectric projects which are at least partly owned by aboriginal communities are eligible for an adder to the purchase price under the Feed in Tariff (FIT). The maximum adder is 1.5 cents per kWh for projects in which the aboriginal community has over 50% equity ownership.

Experience

Several First Nations have applied to the OFA for loan guarantees under the ALGP for renewable generation projects. The most advanced project is the M'Cheeging First Nation's Mother Earth Renewable Energy (MERE) wind power project, a 4 MW project on Manitoulin Island. The project is under construction with the bases for the two wind turbines installed in the summer of 2011.Turbine erection is underway and the project is expected to be in service in the spring of 2012. This project is 100% owned by the First Nation. It has received a loan guarantee of $8.5 million from the ALGP.

Also on Manitoulin Island, the United Chiefs and Councils of Manitoulin (UCCM – a group of the First Nations communities on Manitoulin Island) have applied to the OFA for a loan guarantee for their portion of the McLean's Mountain Wind project, a joint venture between UCCM and Northland Power, an experienced power developer. A complete Renewable Environmental Assessment has been filed with the Ontario Ministry of the Environment and construction start is anticipated in 2012.

The Moose Cree First Nation has received a conditional offer of a loan guarantee from ALGP for its equity investment in the Lower Mattagami project that is planned by Ontario Power Generation for the refurbishment and extension of four generation stations on the Lower Mattagami River.[79]

The process of applying to the OFA for a loan guarantee can itself add value for the project. For example, the OFA due diligence procedure will inspect the partnership agreements between the First Nation and its partner, giving OFA a chance to identify potential future problems in the agreement. The OFA also has helped the First Nations' consultants to understand the

[78] OFA staff suggested that a grant program may be more appropriate if the focus were on smaller size projects.
[79] Source: newsletter from environmental lawyers Willms and Shier. http://www.willmsshier.com/newsletters.asp?id=63

requirements for the project to obtain finance. This can be an advantage during the application for debt finance.

Without the ALGP, it is doubtful that these projects would have progressed as they have. The First Nations communities do not have sufficient financial resources to contribute their share of equity to a project as large as McLean's Mountain. It is possible that they could find a lender or partner to provide a loan for their equity part, but such a loan to a First Nations community would likely carry such a high interest rate as to make the project no longer economic.[80]

Extending this model

Extending this model to community groups would require a commitment from government or other agency, and its successful extension might require more than simply the loan guarantee for the debt portion. The ALGP does not fund the initial development work, such as verifying the resource and performing feasibility studies. The cost of this up front work is much less than the cost of building the project, but is still significant enough to exhaust the resources of some communities. Aboriginal communities in Ontario have access to the Aboriginal Renewable Energy Fund, administered by the OPA, which funds from 40% to 80% of the development costs for renewable projects, with a maximum of $500,000 per project.

Non-aboriginal community projects in Ontario can obtain loans to help with the initial stages of a project. Infrastructure Ontario provides loans that help start capital projects of municipal corporations, including municipal electric utilities. Eligible projects include construction of alternative energy facilities, with maximum funding per project of $500,000. In addition, as noted in the previous case study, Ontario has its Community Energy Partnerships Program.

These two case studies illustrate the support that community-based groups need to help them organize and fund their participation in renewable energy projects. For communities which can access local financial resources, required assistance might be limited to institutional support for the renewable project organization and for the initial phases of the renewable project development. Such communities might also need some funding for development costs like resource assessment and preparation of documents for environmental and other approvals. Communities which do not have such financial resources will likely need financial support for the initial phases of project development as well as access to loan guarantees or other support to fund their equity investment in the project.

6.5 Community Economic Development Investment Fund (CEDIF)

Six CEDIFs have been awarded contracts for the development of twelve renewable energy projects under Nova Scotia's COMFIT program and are the primary financial vehicle that is being used to fund community renewable energy projects in Nova Scotia.

A CEDIF is a pool of capital, formed through the sale of shares (or units), to persons within a defined community, created to operate or invest in local business. It must have at least six

[80] Furthermore, financing projects can be difficult if they are located on reserve lands given legal limitations on land use and requirements for federal approval.

directors elected from the defined community. Investors in CEDIFs qualify for a 35% equity tax credit for Nova Scotia income taxes and are eligible for further equity tax credits of 20 and 10% at the 5 and 10 year investment anniversary. CEDIFs were established to reduce the amount of capital leaving the province through mutual funds and registered retirement savings plans. The CEDIF program was established over 11 years ago and over 40 CEDIFs have invested in a variety of local businesses. The CEDIF model is readily adapted to development of community renewable energy projects.

Eight CEDIFs in Nova Scotia have invested in the creation of Scotian Windfields Inc., which has a mandate to develop community-based wind energy projects in Nova Scotia. One of these CEDIFs is Colchester-Cumberland Wind Field (CCWF) Inc. CCWF has raised close to $1.5 million in equity, secured $1.2 million in debt and has one 800 kW Enercon wind turbine in operation with a 20-year PPA with NSPI and plans to install an additional 800 kW wind turbine and two 50 kW wind turbines. CCWF's success appears to be attributable to a dedicated management team and strong focus on marketing of the shares.

Power Advisory understands that some of the initial CEDIFs that were established to fund the development of renewable energy projects failed when the investments were used for early stage project feasibility assessment and the projects proved not to be economically viable or successful in securing a contract. The COMFIT program clearly mitigates these risks once an application has been accepted.

6.6 Toronto Renewable Energy Co-operative

The Toronto Renewable Energy Co-operative (TREC) was formed in 1999 with the purpose of developing and operating wind turbines. Its wind energy arm, WindShare, is the owner and operator of a single 660 kW wind turbine on the Canadian National Exhibition grounds near the Toronto waterfront. WindShare is a for-profit affiliate of the non-profit TREC.

The total cost of the project was about $1.6 million. This project was developed without any funding from a financial institution. It was built in 2002.

The project is a 50/50 joint venture between TREC and Toronto Hydro. Toronto Hydro paid half of the total project cost and received half of the energy produced as its return. TREC's share of the cost was funded by selling shares to residents of Toronto. Residents purchased a membership share for $1 and then at least five, but no more than fifty, Preferred Shares at $100 each. Over 400 Toronto residents purchased shares, fully subscribing the $800 thousand needed for the project.[81]

TREC's share of the project's initial development was funded through two preferential loans from government sources: a partially forgivable loan from the federal Environment Ministry and a loan from the Toronto Atmospheric Fund (TAF), an agency of the City of Toronto. The federal loan carried no interest. The TAF loan carried an interest rate of 5% and was repayable in nine

[81] Residents actually purchased more than $800 thousand in shares; the excess is held in trust pending investment in future projects.

equal monthly installments from May 1 to December 1 of 2003. Funds to repay the TAF loan came from the co-op members.

This project had a significant technical difficulty due to the failure of its turbine supplier. The supplier went bankrupt essentially as it delivered the turbine. TREC had ordered, and expected to receive, a 750 kW turbine, but the supplier only had a 660 kW turbine. It delivered the smaller turbine with a promise to replace it within a year, but that promise failed due to the bankruptcy. Also because of the bankruptcy, there could be no maintenance and support contract with the original equipment manufacturer. As a result, in the early years of the project the turbine was down for extended periods because parts were not available.

Because the project carried no debt and all of its equity came from Toronto Hydro and from residents willing to accept the risk of project non-performance, it was able to continue to operate throughout these difficulties.

TREC has extended this finance model to create SolarShare. This is a non-profit co-operative whose funds are used to finance a portfolio of large and small solar projects throughout the province. SolarShare sells bonds at $1,000 each, with a 5% rate of return and a five-year term.

6.7 Summary

The following table is a summary of the case studies. The ALGP isn't reviewed given that this information isn't publicly available. For a summary of current market terms see section 5.3.1.

Table 3: Summary of the Case Studies

Name	Shear Wind	Water Power Group	Master Financing Facility	Colchester-Cumberland Wind	TREC
Type of Project	Wind - Private Sector	Hydro – Private Sector	Solar – Private Sector	Wind - Community	Wind- Co-op
Size of Project (MW and $ mm)	62.1 MW ($150 mm)	$3 to $10 mm	<1 MW, portfolios aggregated to min 10 to 20 MW	1.7 MW ($5.15 mm)	660kW $1.6 mm
Capital Structure (% Debt/ Capital)	78%	75% to 85%	45% to 50% (debt) 35% to 40% (tax equity)	48%	50/50 JV with Toronto Hydro 0% debt on coop part
Return on Equity	n/a	n/a	Low-mid teens	9.2%	Varies with profits
Cost of Debt	Fixed rate of 3.462% + credit spread	n/a	n/a	5.75%	5% on Toronto Atmospheric Fund.
Term of Debt	18 years	40 years	15 years (depends on portfolio	5 and 10 years	Repaid within 2 years.

			composition and structure used)		
Structure of Debt	• $114.5 mm total • $107 mm construction financing • $1.6 mm PPA letter of credit • $6 mm for reserves	n/a	• Depends on the financing structure used	$2,475,000	Debt only for early development costs; repaid when co-op financing in place, within 2 years.
Source of Equity	• Inveravante (including a $2.1 mm subordinated loan) • Public markets	n/a	• Developers' sponsor for pure equity and tax equity sponsor for tax equity	Share offering	50% Toronto Hydro; 50% shares sold to local residents with $500 minimum and $5000 maximum investment
Source of Debt	• Banco Bilbao Vizcaya Argentaria SA • Banco Espanol de Credito SA • Instituto de Credito	n/a	• Project finance bank or tax investor which is also a lending institution	Local Cooperative	Environment Canada and Toronto Atmospheric Fund.

Source: Power Advisory

7 Policy Considerations

This chapter reviews government policies that can be used to promote the development of electricity generation from smaller renewable projects and then assesses how they affect project finance for these smaller projects.[82] For this Chapter, we have focused on policies that could find application in Atlantic Canada. Each policy is described, its pros and cons discussed, and where available its degree of success when applied in other jurisdictions evaluated. The chapter draws on information from the developer and financier survey the results of which are reviewed in Section 3.2, on the literature review presented in Section 3.3, and on the experience of the Power Advisory team.

In Chapter 8 of this Report we identify Strategic Policy Options which could be implemented in Atlantic Canada.

7.1 Policies to Support Finance of Renewable Generation

As noted in Section 3.3, policies to promote development from renewables fall in one of three main categories:

(1) Revenue support, or policies that increase the project's revenues or revenue certainty, or both;
(2) Cost reduction, or policies that reduce the cost of the project through direct or indirect subsidies on either construction cost or finance cost;
(3) Market access, or policies that facilitate a renewable project's access to the market either by improving physical facilities or by implementing policy favorable to renewables.

These policies are generally aimed at promoting renewable generation, not specifically at facilitating project finance. But the impact of the policies can be seen in the effect on project finance, both availability and terms. Renewable project finance requires that the projects be economically viable and that project risks are appropriately identified and assigned.[83] By reducing project risks or improving economic viability, government policies can remove barriers to financing renewable energy projects. These effects can be quantified as reductions in the finance cost or in the overall project cost.

A focus of this report is addressing the financing barriers faced by smaller renewable energy projects that are developed by community and aboriginal groups and the challenges posed by the smaller size of provinces in Atlantic Canada. Therefore, this chapter focuses on policies that are

[82] In considering these policies, we address as "small" projects with capacity less than 10 MW, connected at the distribution level, and developed by aboriginal or community groups. We recognize that there are few, if any, points where a project as large as 10 MW could be connected at the distribution level in Atlantic Canada, so the classification of particular projects as "small" under these criteria will sometimes require consideration of the characteristics of the project as a whole, rather than whether it strictly meets these criteria.

[83] In practice, financiers prefer to have a project that has assured prices through a contract with a creditworthy offtaker, a term for the contract that exceeds the term of the finance by several years, an experienced developer, and appropriate allocation of risk between the developer and offtaker.

best suited to these types of projects and expanding the scope of these provincial electricity markets. Appendix C reviews policies that are more appropriate for larger IPP projects.

7.2 Revenue Support Policies

Revenue supports can include a wide range of policies. This section will deal with six commonly used policies that could be, or have been, applied in Atlantic Canada. These are feed in tariffs (FIT), standard offer programs, production subsidies (e.g., ecoEnergy Program), renewable mandates like renewable portfolio standards (RPS), carbon pricing, and requests for proposals (RFP) for renewable energy supply.

7.2.1 Feed in Tariffs

FIT programs have been implemented in Canada in Ontario and, on a limited basis, in Nova Scotia and are being explored in British Columbia. They are widely used in Europe. FIT programs are very effective at enabling the construction of a large amount of renewable energy projects, particularly smaller projects. FIT programs provide economies of scale for financing which enable the construction of smaller projects by reducing the overall due diligence and documentation costs and facilitating the aggregation of smaller projects in larger and easier to finance issuances. (See discussion in Section 4.4) Small project sizes were frequently cited by investors, financiers and developers as a barrier to investment for such projects.

FIT programs provide for the purchase electricity from renewable resources at a price that is intended to enable the developer to recover its cost plus earn a reasonable rate of return. The prices offered differ according to the technology and its size given underlying cost differences. Most technologies for generating electricity from renewables exhibit increasing returns to scale, which means that the overall costs are lower for large projects than they are for small ones. Therefore, following the logic of prices which recover the project costs, larger projects typically receive FIT prices below those offered smaller ones.

Successful applicants to FIT programs receive a PPA from a government agency or a utility. The PPA sets the price for the electricity and the term of the agreement, which typically matches the life of the facility (and therefore influences the term of the financing). Most renewables receive 20-year contracts. Hydroelectric projects can receive longer contracts, with 40-year contracts offered in Ontario.

FIT programs have been very successful in attracting interest from developers with the interest based on the pricing offered, but some of the projects may never come into service. Typical barriers to project success are lack of access to transmission, inability to complete the project profitably at the FIT price, and inability to obtain permits and approvals to meet the required timetable. While FITs can have minimum requirements which ensure a minimum level of project development before contract award, they are typically fundamentally different from RFPs where there are often explicit criteria which favour mature development projects. This difference can cause FITs to have higher project attrition rates.

Table 4 below provides information on the market uptake of the Ontario FIT program. The program is still relatively new, so many projects are still under development or in approval processes. Many other projects are still awaiting assessment of available transmission capacity.

Table 4: Results of Ontario FIT Program

Technology	Applications Number	Applications MW	Contracts Awarded Number	Post-NTP MW	In-service MW	No longer active MW
Wind	295	11,845	77	42	215	2,446
Solar PV	9,633	8,451	1,791	95	26	1,334
Biomass	130	336	50	5	9	111
Hydro	104	366	49	53		23
Totals	10,162	20,998	1,967	195	251	3,914

Source: OPA. Data as of Feb. 3, 2012

NOTE: Post-NTP have received NTP but are not yet in service

These results show the very high level of interest prompted by the attractive features of the Ontario FIT program, primarily the price offered and the long-term PPA from a creditworthy counterparty, the OPA.

As shown above, Ontario's FIT has resulted in more than 10,000 applications for contracts for projects offering over 20,000 MW, for a market with a peak load of approximately 25,000 MW. Of these, almost 2,000, or almost 10%, have contracts executed, while almost 1,500 are no longer active.[84] A total of 183 projects are in commercial operation, providing 251 MW of capacity and a further 385 contracts, representing 195 MW, have received Notice to Proceed but have not yet reached commercial operation.

The inherent limits on the ability to integrate cost-effectively this amount of renewable generation are evident from the challenges of connecting this amount of renewable generation to the grid which has become the primary barrier to greater project participation. This raises the question as to whether consumers are better served by a policy which effectively allocates renewable project development based on available transmission capacity or on the basis of price such as in an RFP.

The German FIT program has been very successful in terms of the amount of renewable generation installed, as Table 5 shows.

[84] Contracts that are no longer active are those that have been rejected or withdrawn, had contract offers expire, or have terminated contracts.

Table 5: Capacity Installed Under German FIT

Technology	2007 MW	2009 MW	2010 MW
Wind: total	22,116	25,230	27,204
Wind: new	1,667	1,859	1,443
Solar PV: total	4,170	9,914	17,230
Solar PV: new	1,271	3,294	7,406
Biomass	3,290	4,102	N/A
Hydro	1,260	1,340	N/A
Gas*	647	641	N/A
Totals	34,421	46,380	53,283

*Landfill gas, sewage gas, and mine gas

Source: German Federal Ministry for the Environment, Nature Conservation and Nuclear Safety

The cost of the German FIT is paid by consumers through a surcharge on electricity prices which pays the difference between the FIT price and the market price. For 2012, this surcharge is scheduled to rise to almost €.04/kWh, or about C$.053/kWh.[85] In 2011 several countries, including Germany and France, reduced funding for their FIT programs due to financial constraints and the rapid reduction in price for solar PV panels.[86]

These examples illustrate the issues raised by a FIT program. The program's price stability and certainty attract investors in renewable energy sources. The benefit to the developer is assurance of earning a reasonable rate of return if it controls cost and performance.

The benefits to the ratepayer include the reduction in the environmental damage caused by electricity generation and, because the price of the renewables is fixed, a hedge against future increases in the price of fuels required by other forms of generation. For this, the ratepayer takes the entire demand risk and typically pays more for renewable electricity than from conventional sources.

The design of a FIT program therefore requires balancing the interests of the developer with the interests of the ratepayer and arriving at prices that properly reflect costs. In the study cited in Section 3.3, de Jager and Rathmann's[87] financial models suggested that programs like a FIT, which offer long-term price support with little risk to the developer, can reduce unit energy costs for a project by 20-30%.[88] This reduction in costs is based on a financial model which assumes that the revenue certainty offered by a FIT results in lower financing costs, i.e., lower cost of debt

[85]Bundesnetzagentur (German Network Agency), "Renewables contribution to change only slightly in 2012", press release Oct. 14, 2011.

[86] Renewable Energy Network for the 21st Century (REN 21), Renewables 2011, Global Status Report, pg. 49.

[87] David de Jager and Max Rathmann, op. cit.

[88] Power Advisory's financial model confirms up to the middle of this range.

and equity and greater leverage.[89] Power Advisory believes that a well structured PPA can provide equivalent lower financing costs and that an RFP can be more effective in ensuring that the renewable resources for which contracts are offered have lower overall costs. However, RFPs are better suited to larger IPP projects whereas FITs are better suited to smaller community and aboriginal projects.

Similarly to a RFP process with a financeable PPA, a FIT program can greatly facilitate financing for IPP developers. By providing price and demand certainty, it reduces risk and therefore finance rates thereby improving access to capital. IPP developers like FIT programs as they reduce the riskiness of development capital. Under a FIT a developer has greater control over project success. Furthermore, pricing is not competitive and provides higher returns for good sites. Uniform financing documents also allow IPP developers to accelerate the development of projects.

Well-designed FIT programs are likely to be appropriate and effective in Atlantic Canada. In theory, proper analysis of the costs for projects by size and technology would allow FIT programs to offer prices that will attract projects but not be overly generous. The price stability that FIT programs provide will help even small projects obtain financing. However, changes in the costs and performance of technologies cause FITs to have greater implementation risks for the buyer. These implementation risks can be managed through program design, e.g., procurement caps, price degression and regular program reviews.

7.2.2 Standard Offer Programs

Both standard offer and FIT programs offer long-term PPAs at a known rate for qualifying renewable generation projects. There are several differences between them in practice, although some programs called FIT programs have more of the characteristics of a standard offer program.

A standard offer program sets a uniform rate for all (or most) of the eligible renewable power sources. The rate is based on the value of the electricity. For example, the standard offer rate could be considered to be related to the system avoided cost, defined as the full cost of the cheapest alternative source of new power supply (including its environmental damage cost).

In Ontario, the standard offer price was based on the price at which renewable power had been offered in a recent RFP. The program set a size limit of 10 MW per eligible project because the standard offer program was aimed at projects too small to compete successfully in an RFP process. The Ontario experience with its FIT program showed that the rules did not prevent developers from offering large projects (cut up into smaller tranches), that the larger developers thus froze out smaller projects, that the rules did not sufficiently incent developers to make continuous progress on their projects, and that the prices were not high enough to attract many smaller projects. Nonetheless, some capacity was developed and put into service under the Ontario FIT program.

[89] Additional, albeit smaller, savings are likely to be provided by the lower development costs offered by a FIT.

Standard offer programs limit cost exposure for ratepayers, because they base the price offer on the value of the electricity to the system, not on its cost. As with other programs, ratepayers are exposed to higher costs from any premium of the standard offer price over the cost of other sources of electricity.

However, standard offer programs may not produce the desired amount of renewable supply because the price may not cover costs for many potential projects and technologies.

Issues in the design of a standard offer program include what forms of generation are eligible, whether there is a size cap on individual projects, whether there is a cap on the total amount of electricity to be purchased under the standard offer, the term of the PPA offered to standard offer participants, and how long participants have to bring their projects into operation.

Like FITs, standard offer programs provide favourable conditions for finance of renewable IPP development by giving a PPA with appropriate terms and a fixed price. Prices under standard offer programs are not technology specific so they are likely to be lower than with FITs, lowering the number of projects that can be financed. They also do not take account of the cost implications of smaller projects' inability to access economics of scale. They may not be as readily applicable as a FIT program in Atlantic Canada to attract small projects.

7.2.3 RFPs

RFPs provide revenue support by offering PPAs with a price specified to in their offers to successful bidders. If the PPAs are well designed and properly allocate project risks, they can form the basis for financing the project. Our survey gave the characteristics of such a well-designed PPA: the contract term should equal the life of the asset allowing a longer financing term; the price should be sufficient to cover the cost plus appropriate debt coverage; the offtaker should be creditworthy; and the terms of the contract should properly allocate risk between the developer and the offtaker.

RFP programs that are successful from the buyer's point of view attract significantly more offers than needed. That allows the buyers to choose suppliers that are technically competent and offer the lowest prices. RFP programs that are successful from the bidder's point of view are those that offer a PPA with favorable terms and a high probability of winning a contract.

Because the contracts in RFP processes are awarded to low-price bidders, there may be project attrition if the successful bidders find they cannot earn a reasonable return at their bid price. This risk can be mitigated by also considering the developer's experience and capabilities and assessing the project maturity. Some RFP buyers provide for this attrition by awarding contracts for more capacity or generation than they want to buy. In British Columbia, for example, BC Hydro's clean power calls are for 30% more than desired to allow for attrition. In Ontario, the OPA's Renewable Energy Supply III RFP had an attrition rate of about 13%, in part due to more stringent minimum thresholds.

In Atlantic Canada, RFPs have been used with considerable success as a mechanism to meet RPS requirements and have resulted in the construction and operation of over 600 MW of renewable power projects. However, these have been larger projects.

RFPs can also be designed to facilitate smaller projects. An RFP process to attract smaller developers should have less onerous participation requirements and offer a higher probability of success. To make the process less onerous, the process could accept projects at an earlier stage of development than is required for RFPs aimed at larger projects with more experienced developers. For example, it need not require that the participants already have all their financing committed nor that they already be engaged in the environmental permitting process. Requirements for resource data could also be eased. To increase the probability of success, the RFP could have an upper limit on the size of project to be accepted and have a large enough overall procurement total to ensure that several projects will be accepted.

7.3 Cost Reduction Policies

As the research cited in Section 3.2.3 showed, one of the most effective ways to reduce the cost of renewable generation is through reducing financing costs. That is the mechanism through which most of the revenue support policies work. A similar mechanism can work through policies which reduce risks or costs, since they have the same effect of increasing the rate of return and reducing the risk.

7.3.1 Loan guarantees

A loan guarantee from a creditworthy source (typically a government or government agency) directly reduces the finance cost by guaranteeing the repayment of all or a portion of the debt capital, thereby reducing the risk to the lender. Many projects would not be built without a loan guarantee because the capital would not be otherwise available or the project would be cost prohibitive to build.

Ontario has a loan guarantee program for projects undertaken by First Nations or Métis. The Aboriginal Loan Guarantee Program is described in more detail in Section 6.4 of this report. Without the ALGP, aboriginals would not be able to finance the extent of equity participation in renewable projects they have reached in Ontario. Some level of aboriginal equity participation is needed to qualify for the aboriginal adder to the FIT price for the kinds of renewable generation that are eligible for the adder.[90]

In the United States, the Department of Energy (DoE) administers loan and loan guarantee programs to support commercialization of technologies and technologies that avoid, reduce or sequester greenhouse gas emissions. They recently approved $1.2 billion in a partial loan guarantee to fund a 250 MW solar PV facility in California[91] and $1.4 billion in a partial loan

[90] In the Ontario FIT program, projects using eligible technologies can receive an adder, or premium, to the stated FIT price if they have equity participation from aboriginal or community groups. The level of the adder depends on the fraction of equity; it is a maximum of 1.5 cents per kWh for projects with 50% or more of equity coming from aboriginal group(s).

[91] US Department of Energy, "Energy Department Finalizes $1.2 Billion Loan Guarantee to Support California Solar Generation", Press Release, Sept. 30, 2011. http://energy.gov/articles/energy-department-finalizes-12-billion-loan-guarantee-support-california-solar-generation

guarantee for a multi-state project to install rooftop solar PV units.[92] The DoE programs have committed loans, loan guarantees, or conditional loan guarantees of almost $40 billion.

Other mechanisms are state-guaranteed loans from banks, as in Germany, or loans through special bond issues, as in the Netherlands.

Loan guarantees can be an effective tool at reducing the total cost of financing. Government loan guarantees increase the total amount of debt which can be raised against the project, thereby reducing the amount of (more expensive) equity which will need to be raised. In addition, Government loan guarantees can reduce the cost of debt, and the de Jager and Rathmann study[93] estimated that a government loan guarantee can reduce the cost of debt by 1-2%. They estimated that this reduction in the debt cost could reduce levelized energy cost by 5-10%. In the case of the Ontario Aboriginal Loan Guarantee Program, the impacts may be even greater, because lenders are likely to be reluctant to lend to these borrowers without a guarantee.

Before granting loans or loan guarantees, the governments perform due diligence similar to that of a commercial lender. With proper due diligence, and especially if the project has revenue support, the default rates on such loans will be low and the cost to the government low. Credit rating agencies may count the guarantees when assessing the total debt position of the government, which will not be a significant problem if the loans are not a large fraction of the total government borrowing capacity.[94]

Loan guarantees have been effective in creating opportunities for aboriginal groups to participate in the FIT program in Ontario. They have given the aboriginal groups the ability to attract the attention of experienced developers of all sizes, making the projects viable both technically and financially. Such guarantees could be very useful in promoting similar projects in Atlantic Canada.

7.4 Market Access Policies

Market access policies do not directly affect the cost of the projects. They can improve project economics by reducing uncertainty over access to the electricity supply system.

7.4.1 Market size

In most jurisdictions, overall size is not an issue for market access for renewables. Either the jurisdiction itself has a large enough market, as in Ontario or Germany, or it is strongly connected to large markets, as in the smaller New England states which have access to the broader New England market, or Denmark, which has access both to Germany and Norway. A large market allows the development of multiple renewable projects, each large enough to take advantage of available economies of scale in construction, finance, development and operation.

[92] US Department of Energy, "Energy Department Finalizes Loan Guarantee for Transformational Rooftop Solar Project", Press Release, Sept. 30, 2011. http://energy.gov/articles/energy-department-finalizes-loan-guarantee-transformational-rooftop-solar-project
[93] David de Jager and Max Rathmann, op. cit.
[94] However, as discussed, the obligations of the Aboriginal Loan Guarantee Program in Ontario are not considered an obligation of the Province.

As our survey showed, the size of the renewable market in Atlantic Canada can present a significant barrier to the development of projects. With the market for larger projects driven by RFPs, the number of RFPs is limited, which increases the risks of participation since projects which are unsuccessful must wait for extended periods for the next sales opportunity. Furthermore, a smaller market can make for smaller projects, and the smaller projects have more difficulty in attracting experienced developers and in obtaining finance.

The best remedy is to increase the market size, which in Atlantic Canada means stronger interconnections and cooperation. The premiers of New Brunswick and Nova Scotia have announced a continued commitment to collaboration on energy issues.[95] The announcement pointed to optimization of the transmission system as one area for collaboration. Both provinces have committed to increasing the share of renewables in their electricity supply.

Collaborative efforts that would increase the effective market size would include strengthening transmission ties between each of the various jurisdictions (e.g.,New Brunswick and Nova Scotia) and eliminating rate pancaking for projects within the control area.

Collaboration could also improve market size for renewables by coordinating procurement across jurisdictions. For example, the next RFPs could be issued jointly by the two provinces, increasing the amount of supply called for and therefore the number of potential projects of large enough size ($30-50 million in finance) to be more readily financed. This would help address a problem that several survey participants identified.

7.4.2 Renewable Energy Aggregator

As IPPs continue to look to develop renewable power projects in Atlantic Canada for sale into New England, they could profit from the presence of a renewable energy aggregator. Small developers, especially, might not have the market experience to be able to address issues of obtaining transmission access to New England, of selling renewable energy credits to buyers in New England, and of managing the delivery of the electricity. An aggregator which possesses these skills and knowledge can provide them efficiently to small developers.

An aggregator is better able to efficiently use transmission which a single project might not be able to justify contracting for given its load factor or the uncertainty regarding future market opportunities in the jurisdiction. Furthermore, an aggregator is more likely to possess the necessary forecasting and scheduling capabilities and to have a diverse mix of generation resources that better allows it to meet firm customer requirements and thereby secure higher prices. The aggregator would sell the renewable power into the most promising market over the available transmission path. That could include exports to the United States through existing interconnections, through new facilities built in conjunction with the Muskrat Falls development in Labrador, or through Québec to Ontario or the United States.

Improved collaboration of these kinds could help facilitate finance by broadening the markets for the power.

[95] Government of New Brunswick, "New Brunswick and Nova Scotia Commit to Continued Energy Collaboration", press release, May 16, 2011.

7.4.3 Transmission access

Renewable resources are generally not located close to loads, nor are they necessarily close to existing transmission facilities. Access to the transmission grid is a critical issue for renewables.

In Nova Scotia, as our survey pointed out, Cape Breton Island already has a surplus of generation and not enough firm transmission capacity to reach the load centre of Halifax. Yet Cape Breton has some of the best wind resource in the province. Bidders to the current RFP who want to propose projects on Cape Breton may find that they would result in network upgrades that cause their projects to be uneconomic.

In Atlantic Canada, an action that could increase the size of the market is to increase transmission interconnection capacity with New England. The recent addition of the International Power Line in 2007 has already increased the opportunity for trade. Effective expansion of export capacity to the major load centers of New England may require transmission reinforcement within New England unless new transmission paths are developed that allow direct access to the southern New England market which is the main load centre.

The *Ontario Green Energy and Green Economy Act* required transmission owners to give priority in access to electricity from renewable projects. The first projects approved in the Ontario FIT were those which could obtain access to the Ontario transmission system. Of the applications under the general FIT program, projects representing 6,973 MW of capacity do not have transmission access and are waiting for a test to determine if connecting them to the system is economic, as opposed to a total of 4,752 MW of capacity that has been awarded contracts.[96]

Governments can implement policies to ensure that adequate transmission is available to meet the needs of renewable developments. However, this is likely to result in higher transmission costs and overall electricity prices and is not necessarily in the best interests of customers. Ideally, planners and purchasers should consider the delivered costs of renewable energy. Even with such policies, however, developing new transmission lines is a lengthy process with consultations with landowners and others affected by the line as well as environmental considerations for a linear project over long distances.

If the transmission facilities are not built or reinforced to accommodate an increasing penetration of renewables, transmission congestion will increase. Managing transmission congestion and who bears the risk of it will be increasingly important. Requiring IPPs to bear this risk without limits or mitigation strategies will increase financing costs. However, passing these risks through to the purchasing utility and ultimately their customers can lead to poor project siting decisions. Solutions need to consider existing market rules and market structure and the available transmission infrastructure.

Network access can become an absolute barrier to the development of renewable generation facilities. In Atlantic Canada, some small projects may be able to connect at the distribution

[96] Ontario Power Authority, "Bi-Weekly FIT and microFIT report", data as of Dec. 23, 2011. Of the 20,574 MW submitted, the remainder have not yet had their reviews completed or they have been withdrawn.

level. Studying the capacity of the distribution networks to accept generation could help the development of such projects.

In Nova Scotia, for example, NSPI has a map on its website showing all of its distribution feeders, with links that give an estimate of the capacity of each station to connect COMFIT capacity.[97] This information is not dynamically updated to show the changes to capacity as new generators or new loads connect or as other changes take place to the distribution system. It therefore does not give a firm indication of available capacity at any time; that can only be determined by a Distribution System Impact Study, which is an essential part of the connection process. However, it does provide potential generators with basic information that can at least warn them away from feeders which are highly unlikely to accept their proposed generation, and can also point to those feeders more likely to be able to accept them.

In Nova Scotia, New Brunswick and PEI, the procedure for transmission connections is set out in the respective Open Access Transmission Tariffs (OATTs).[98] The New Brunswick System Operator issued a draft report on connection requirements for renewable generators in the summer of 2009, but it has not been made final. It deals only with projects of at least 5 MVa and is mostly concerned with technical issues. For procedure, it refers to the generation interconnection procedures in the OATT.

[97] http://www.nspower.ca/en/home/environment/renewableenergy/comfit/capacity.aspx
[98] Under that procedure, the potential generator applies to the transmission provider, who then performs a Interconnection Feasibility Study which begins the process of identifying necessary network upgrades and the costs of interconnection to be paid by the generator.

8 STRATEGIC POLICY OPTIONS

In this chapter, Power Advisory presents a number of strategic policy options that may facilitate the financing of small renewable electricity generation projects in Atlantic Canada. These options focus on those which will facilitate financing of small projects because our survey and case studies show that larger renewable energy projects can get financing under essentially the same conditions and with the same attention from lenders as do similar projects elsewhere in Canada.

The first group of strategic policy options is those which affect the Atlantic Canada region as a whole or which require concerted action by more than one government, provincial or federal. Because they would affect the entire region and generally are focused on overcoming barriers to trade within the region, these policy options would have a more significant impact on larger renewable energy projects. The second set of policies is focused more on addressing financing barriers faced by small renewable energy projects and these policies can be implemented by and for individual provinces.

8.1 System Integration

Electricity trade, including trade in renewables, can be increased by closer integration of the electricity systems of Atlantic Canada.[99] The extent of possible integration is limited by the capacity of the physical connections, but even within that context integration can be enhanced through better coordination and harmonization of the market rules.

The systems of New Brunswick, Nova Scotia and PEI are already reasonably well integrated, with the NBSO acting as the balancing authority for the entire area. However, as the co-operation agreement between the premiers of New Brunswick and Nova Scotia showed,[100] coordination can still be improved between the provinces.

Enhanced system integration would be promoted by reinforcing transmission interconnections among provinces, eliminating rate pancaking whereby parties pay transmission tariffs for each Province through which they wheel power, and employing consistent market rules. The Premiers of Nova Scotia and New Brunswick proposed such a strengthening of the transmission link in July, 2010, when they announced that the two provinces were exploring better connecting the provinces with a new 500 MW transmission line.[101] The addition of a direct transmission link from Newfoundland and Labrador as part of the Lower Churchill Project development would

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[99] The *Eastern Wind Integration and Transmission Study* found that high penetrations of wind (20 to 30%) are technically feasible with significant expansion of transmission interconnections. The study found that "transmission helps reduce the impacts of the variability of the wind, which reduces wind integration costs, increases reliability of the electrical grid, and helps make more efficient use of the available generation resources." (p. 27).

[100] Government of Nova Scotia, Premier's Office Press Release, "Nova Scotia and New Brunswick will Work to Further Strengthen Regional Energy Co-operation", Nov. 19, 2010. The press release mentions "co-operation to improve transmission, system operation, renewable energy production and other aspects of their electric power systems."

[101] Government of Nova Scotia, Premier's Office Press Release, "New Energy Partnership Forged between Nova Scotia and New Brunswick", July 20, 2010.

allow that province to be linked to the electricity system in the rest of Atlantic Canada. A new line between Nova Scotia and New Brunswick would facilitate export of Lower Churchill and other renewable electricity generated in Atlantic Canada to the US Northeast.

8.2 Policy Harmonization

As described in Chapter 2, the four Atlantic Canada provinces have differing policies for promoting the development of electricity generation from renewables but they have similar goals and use similar instruments in some cases. In particular, New Brunswick, Nova Scotia, and PEI have RPS standards which are to be met by procurement of renewables through FIT (in Nova Scotia) and RFP (in all three provinces) processes.

So far, these have been separate processes, each with different sets of rules and different qualifications for bidders (e.g., mandating that projects be located in the province issuing the RFP). Harmonizing the terms and conditions of the RFP processes would relieve potential bidders of the requirement to become familiar with differing sets of bid conditions; allow them to potentially participate in multiple RFPs increasing the potential for being awarded a contract and could encourage more participation. Under this example, policy harmonization can be as simple as allowing renewable resources from other jurisdictions to satisfy the RPS or participate in the RFP. However, to the degree that there is a premium paid for renewable energy resources that will increase electricity rates, policymakers are likely to prefer that projects be located within the province so that there are offsetting economic development benefits realized. Power Advisory's study for NRCan showed that there can be significant benefits of allowing neighboring jurisdictions to meet RPS requirements.[102]

8.3 Renewable Aggregator

The New England states have renewable obligations of about 18 TWh. While the New England market isn't attractive at currently low energy prices, given this demand for renewable electricity it is expected to be an important market in the future.

However, the costs of identifying and negotiating trades, securing transmission, and scheduling them on the system do not decrease proportionately with the size of the trade. Therefore, for smaller sellers, these transactions costs are a relatively high fraction of the price they can expect to obtain. Such relatively high costs create a barrier to trade for small developers. Furthermore, one project, particularly wind projects which operate at maximum capacity a relatively limited amount of time, often cannot cost-effectively contract for required transmission capacity.

These barriers could be mitigated by the creation of an aggregator which would negotiate trades, secure transmission and schedule the electricity for a number of smaller developers. The aggregator could thereby spread the transaction costs over a larger volume of trade, making the trade feasible. Furthermore, having a portfolio of projects would enhance the degree of firmness of the energy offered and reduce the effective cost of transmission and the risks of imbalance penalties.

[102] "The Potential Impact of Relaxing Renewable Portfolio Standard Constraints on Canada-US Electricity Trade", March 31, 2011

The aggregator need not be a government agency. It could be part of an existing utility in Atlantic Canada or it could be a private firm that offers such transaction services. There are a number of entities that maintain a trading desk and already act as an agent for other generators in Atlantic Canada and possibly could become a renewables aggregator for the region.

Having a single aggregator for the region would also strengthen integration.

Governments could agree to create an aggregator or they could help to fund the establishment of an aggregator.

8.4 Facilitate Distribution Level Connection

As the Nova Scotia COMFIT program shows, connecting small renewable projects at the distribution level can avoid some of the issues with transmission congestion, at least initially. Allowing or facilitating such connection can increase the capacity of the system to integrate renewable projects. Because the capacity of the distribution system is inherently limited, such connections would be restricted to smaller-scale projects and to a finite total.

Governments could facilitate such connection ability by encouraging or requiring the distributors to study their systems and determine ability to connect renewable generation at specific points of their distribution systems. The NSPI website showing available capacity for each feeder could be replicated in the other Atlantic Canada provinces.[103] Such information is particularly important for a FIT program where connection capacity is likely to be a critical determinant of project viability and less important for an RFP where project selection is likely to be based on a range of criteria. Each province would have to consider whether the value of information to prospective renewable generators provides sufficient benefits to warrant the costs.

Distribution owners can also help facilitate generation connection by consulting with the groups who might propose to build generation. Such consultations can be more specific, but a large volume of them would also require a significant commitment of resources by the distributor.

8.5 Focused FIT Programs

A FIT program focused on smaller projects offered by target groups can attract participation by them.

For example, the Nova Scotia community FIT (COMFIT) program is narrowly focused on smaller projects and has attracted over 95 applications to February 2012. Only certain kinds of organizations are eligible to participate in this program and only with certain kinds of renewable technologies.

[103] Hydro One, the distributor serving the largest service territory in Ontario, has a similar website which provides a list of station connection capacity, a list of applications and an example showing how to calculate connection capacity. http://www.hydroone.com/Generators/Pages/AvailableCapacity.aspx

A focused FIT program can avoid many of the problems seen in larger FIT programs like those in Ontario and Germany.[104] For example, one of the conditions for the Nova Scotia COMFIT program is that the project be able to connect at the distribution level. This requirement ensures that no one project can be too large because of the limited capacity of the distribution system to accept injections.

These conditions avoid the potential for the program to become too large relative to the size of the electricity supply system or the requirements for renewable power. A FIT program could also be designed with caps, either on the total program or on some technologies (solar PV, for example).

8.6 RFP Processes

RFP processes are typically designed to ensure participation by large, experienced developers, as they have done in New Brunswick and Nova Scotia. Appropriately stringent conditions for RFP participation can increase the probability that all the projects selected in large-scale procurements are built.

But as noted in Section 7.2.3, RFP programs could also be designed to facilitate participation by small projects as defined in this Report. In our survey, small developers said that they were deterred from participating in RFP processes by several factors: the high cost and difficulty of meeting the mandatory requirements, including the financial requirements, and the risk due to the low probability of winning[105] and the high cost of participation relative.

To design an RFP process that could be more effective in attracting small bidders, and in facilitating the ultimate financing of the project, the procuring agency could soften the mandatory requirements, such as having less stringent financial and environmental approval requirements. Assuming that the RFP was targeted at community and aboriginal projects it could also be designed with a size cap for proposals or firms, ensuring that all successful projects meet the definition of small. For example, a 50 MW procurement could have a 10 MW size cap, thus ensuring at least five successful bidders. To broaden the pool of winners, proponents could be prohibited from being affiliated with other proponents.

Relaxing these mandatory requirements would increase the risk that proponents successful in the RFP process would be unable to complete the projects. The procuring agency would need to monitor progress closely.[106]

[104] These include adverse impacts on customer rates and overwhelming the system's connection capacity, triggering major network investment.
[105] Because so few winners can be successful given the amount of total capacity sought and the size of the likely offers.
[106] The PPA might also contain some financial penalty for successful proponents who are not able to complete their projects, recognizing that the size of these penalties will affect participation and that securing funding prior to contract award is more difficult.

8.7 Loan Guarantees

To facilitate First Nations' participation in renewable electricity generation, Ontario created its Aboriginal Loan Guarantee Program (ALGP). It has been essential to allow such groups to raise their equity portion of the investment.

Participation by First Nations in Atlantic Canada could benefit from similar action. Eligibility for such loan guarantees should be tightly focused on groups whose participation the governments want to encourage and which are likely to have difficulty in raising equity capital on their own. These would likely be limited to First Nations and community groups. In Nova Scotia, participation by community groups has been facilitated by the CEDIF, reducing the need for such a program in Nova Scotia.

Such programs do not have a high net cost to the government if due diligence is properly applied and default rates are correspondingly low. With no defaults, the program's net cost is its administrative cost if its total lending is not high enough to affect the government's credit rating or borrowing ability. However, performing the required due diligence can require considerable resources; recall that the OFA anticipates reviewing about four applications per year under the ALGP.

Loan guarantee programs are also effective at promoting the development of new technologies. A new generation technology being developed in Atlantic Canada is tidal power. Governments could offer loan guarantees to help fund the construction of tidal power projects. Such funding could be similar to that given other promising new technologies to help them achieve commercial scale. Government loan guarantees would be needed because other sources of funds, especially debt finance, seek projects where there is little technical risk and the technology is proven to be commercially viable. In this case, of course, the government is assuming greater default risk, with the intention of promoting a technology that would, if it proved viable, add to economic activity in the province.

8.8 Development Cost Funding

Groups that the government may want to target for participation in development, like First Nations and community groups, may have difficulty in funding the early development costs of a project. These include resource assessment, environmental assessment costs, project engineering, application costs, and other costs incurred before the project receives a contract and can access its project finance. In Ontario, the OPA funds such costs for aboriginal and community groups to a maximum of $500,000 per project.

The federal department of Aboriginal Affairs and Northern Development funds the ecoENERGY program for renewable energy for northern and aboriginal communities. It provides up to $250,000 in funding to aboriginal and northern communities for development activities, such as pre-feasibility and feasibility studies for renewable generation projects.[107] No aboriginal groups

[107] This program is not accepting applications at this time. The website says that an announcement of funding for the 2012-13 fiscal year will be posted as soon as it is available. http://www.aadnc-aandc.gc.ca/eng/1100100034258

in Atlantic Canada have accessed this funding for renewable energy projects, though those in other provinces have, including several in Ontario and Québec.

Community groups in Atlantic Canada may be unable to obtain sufficient funding for these up-front activities. Establishing a method of development cost funding would provide the necessary resources for early project development.

As for the loan guarantee programs, this development funding should be narrowly focused on those groups whose participation governments want to facilitate and which are not likely to be able to secure funding themselves. The program should also ensure that the groups being funded have a good likelihood of being able to develop a project.

In Nova Scotia, the existing community investment program, CEDIF (Community Economic Development Investment Fund) has become a vehicle for such funding, as described in Section 6.5 above. CEDIFs raise money from within defined communities which is then invested within the community or used to operate businesses within the community. They must not be charitable or non-profit. Many of the participants in the Nova Scotia COMFIT program have used CEDIF vehicles for their funding. However, using CEDIFs to fund initial project development activities is problematic given that these development activities are the most risky and investors in CEDIFs are seeking a return. Therefore, if these development expenses demonstrate that the project isn't viable and the CEDIF was organized to fund the development of this one project then investors will lose their entire investment.

8.9 Facilitate Cooperative Development

As the examples of the Water Power Group, CEDIF and TREC showed, cooperative developments, especially community-based cooperatives, can be effective in funding small-scale renewable energy projects.

Raising equity from the community can give the project more leeway because the local pool of equity investors may be more patient with returns that are lower than expected. For some members of local cooperatives, part of the benefit they receive is simply knowing that they have helped to build a renewable energy project in their community, a project that is visible to them and others. Not all community investors take this view, but an honest offering circular that describes the risks can mitigate impatience.

Such cooperatives may be able, as TREC was, to avoid institutional funding. Alternatively, as the Water Power Group's experience shows, the co-operative model can help to obtain loans if it allows a larger financial scale.

Governments can support these initiatives by enacting appropriate legislation so that renewable energy cooperatives can be formed. In PEI, municipalities are prohibited from investing outside their community. In Ontario the co-operative legislation primarily contemplated either buyer (as in agricultural) or seller co-operatives. Renewable energy co-operatives did not fit this model. Other limiting provisions might prevent a municipality from cooperating with neighboring municipalities when the project is not located within its municipal boundaries.

APPENDIX A: INTERVIEW GUIDE

Study on Financing of Renewable Electricity Projects in Atlantic Canada

Background:
Power Advisory LLC (Power Advisory) has been engaged by Atlantic Canada Opportunities Agency (ACOA) to identify and analyze the challenges in the financing of renewable energy projects in each of the four Atlantic Provinces with jurisdictional comparisons to other regions. The study is to identify and evaluate the key economic conditions and risks that affect the availability and cost of capital for independent power producers associated with renewable electricity projects. The study is focusing on the risks, the economic and market conditions and the policies, actions and favourable market that have mitigated these risks/conditions elsewhere. A key deliverable will be recommendations as to how the Atlantic Provinces may take full advantage of the opportunities afforded by the region's renewable energy potential.

Purpose of Interviews:
We are conducting interviews with renewable project developers, investors and lenders to guide us in identifying and analyzing the challenges in financing renewable energy projects in each of the four Atlantic Provinces. Your participation in this interview will enhance our understanding of these issues. Thank you for your participation.

Q1. In what provinces in Atlantic Canada have you attempted to develop renewable energy projects?

New Brunswick □ Newfoundland and Labrador □ Nova Scotia □ Prince Edwards Island □

Q2. Have you developed renewable energy projects in other jurisdictions?

If so, please identify:____

Q3. What types of renewable energy project have you attempted to develop in Atlantic Canada?

Wind □ Biomass □ Hydro □ Tidal/Wave □ Solar □ Other

Q4. What size of projects have you tried to develop in Atlantic Canada?

Size ($ mm): ______________________ Capacity (MW): _______________________

Q5. Have you been successful in your project development efforts in Atlantic?

Yes □ No □ Please explain:____

____

____

Q6. Have there been issues associated with securing financing for your Atlantic Canada project development efforts? Yes □ No □ Please explain:____

____
____

Q7. Have the financing issues for your Atlantic Canada renewable projects been related to securing a market for the output of the project? Yes □ No □ Please explain:____
____
____

Q8. Are the financing challenges for renewable projects in Atlantic Canada attributable in part to a lack of information for investors and lenders? Yes □ No □ Please explain:____
____
____

Q9. Are there unique technology risks that renewable projects in Atlantic Canada face relative to other jurisdictions? Yes □ No □ Please explain:____
____
____

Q10. Are there unique (or greater) regulatory risks that renewable projects in Atlantic Canada face relative to other jurisdictions? Yes □ No □ Please Explain:____
____
____

Q11. Do you view the risks and economic conditions that affect the financing terms for Atlantic Canada renewable projects as less favourable than those that are likely to be available for similar projects in other jurisdictions? Yes □ No □ Please explain:____
____
____

Q12. Do you believe that there is a shortage of equity and debt financing available for renewable projects in Atlantic Canada? Yes □ No □ Please explain:____
____
____

Q.13 In your experience, would you say that the difficulty of financing renewable energy projects in Atlantic Canada is greater than that in other jurisdictions? Why? Please explain:
____
____
____

Q14. Is this shortage of equity and debt financing more pronounced for small renewable projects in Atlantic Canada? Yes □ No □ Please explain:____

____

____

Q15. Do you have any recommendations regarding how the risks and economic conditions for project financing can be made more favourable for Atlantic Canada renewable projects? (Please make sure where possible to tie these recommendations to the challenges and barriers you identified.) Yes □ No □ Please explain:____

____

____

____

____

Q16. Are there financing vehicles that can be employed that would improve the availability of equity and debt to renewable energy projects in Atlantic Canada? Please identify:____

____

____

Q.17 Are there ways in which governments or buyers of the output of these projects can work with the private sector to ensure that these risks of these projects are accurately assessed and not overstated? If so, please identify:____

____

____

Q18. Please list any other concerns or forms of support you believe would assist your project development not already addressed:____

____

APPENDIX B: INTERVIEW NOTES

Interviewers: Ching-yen Chen, Potian; John Dalton, Power Advisory; Mitchell Rothman, Power Advisory
Subject: Financing Renewable Projects in Atlantic Canada
Date: Nov 15, 2011 (Phone Call)
Category: Lender

* Company has financed renewable projects (all except Tidal) in Canada and the US. Within Atlantic Canada, has financed wind and hydro projects in Nova several provinces

* Key determinant for whether they will participate is size of the debt

* Target size is $75 to $100 mm. At sizes above $100 mm they will syndicate to parties (2 or 3 other parties on a club basis). Minimum size is $50 mm.

* Minimum size is due to corporate pressures of a $mm target amount of capital to deploy and limited internal resources. Time commitment per transaction is "fixed", which is why they target larger deals.

* Have also found a strong correlation between size and competency (e.g. more experienced developers are typically associated with larger projects). Less experienced developers require more hand-holding

* Examples in other jurisdictions show that well-structured projects of a good size will attract capital at competitive prices (think Saskatchewan was seeking 250MW but received over 5,000 MW in bids)

* Otherwise, no real issue with investing in Atlantic Canada

* Key issues in determining whether to invest capital is an examination of the PPA agreement to ensure the terms make the project financeable. For renewable power, there will be no project without a contract in hand, but to get financing the contract terms must be reasonably favourable to the developer. An example of a less favourable contract is one with large penalties to the developer for missing minimum output levels.

* Risks which need to remain with equity - completion, availability, interconnection

* Risks which need to remain with the PPA counterparty - resource (no min production levels but availability ok), curtailment

* Risks which should not be in the contract - local content (introduces risks, is expensive and is not an effective means of producing long-term employment)

* No issues with current contracts in Atlantic Canada, and in some cases they are more favourable to the developer than those elsewhere. For example, in Ontario the developer takes the curtailment risk.

* Other determinant is making sure the project has access to transmission

* Ensure the transmission rights and curtailment risks are on a queue basis (and not like Texas where every entrant is equally curtailed)

Other topics
* Ability to bundle smaller projects together into a larger financing - possible but difficult because projects must be built around the same time (<6 months), and the ownership must be common between projects

* Best way to encourage renewable development in Atlantic Canada is to ensure transmission connection is available and contracts are financeable.

*We look for some experience in a developer, but we have been willing to be patient and we have done a fair amount of holding developers' hands.

*FIT programs - does not like it / believes RFPs are much better in procuring the most competitive pricing for projects

* With any procurement process, they key is having a pre-qualification process or stringent threshold requirements to ensure credible bidders (or you will have the Ontario experience)

* Atlantic Canada has an advantage over some other jurisdictions, such as BC, because the First Nation rights are clearer

Interviewers: Ching-yen Chen, Potian; Mitchell Rothman, Power Advisory
Subject: Financing Renewable Projects in Atlantic Canada
Date: Nov 15, 2011 @ 2 pm (Phone Call)
Category: Medium-sized Developer

* Has not yet invested in Atlantic Canada

* No issue with region, just that projects brought to them previously have not been economic subject to further DD

* Flaw identified in diligence which reduces economics, or risks in the PPA structure

* Main issue is whether the PPA economics are rich and secure enough to support the project: How secure is the revenue stream? It is then their lookout as buyer to determine how secure the output is.

* Governmental agency (good credit risk)

* Dispatch rules do not constrain revenues
* Typically buys the early stage project from the developer (developer has secured land, permits, wind data)

* Seeks minimum project sizes in order to be competitive. This is what limits the number of projects they see in Atlantic Canada

* wind - 30 - 50MW

* water - 4-5 MW

* solar groundmount – 7-10MW

* solar rooftop - large portfolio

* biomass - 20MW

* Projects smaller than those identified above are typically too small to support the fixed cost overheads both physical and administrative (eg., legal) -> economies of scale are key

*But if the project is good enough, size is not an issue. We will look at projects of any size if the PPA is rich enough. Could finance a 5 MW project without borrowing, but would prefer to aggregate, say, 6 x 5 MW projects in the same area.

* Strong preference for the counterparty to be the government. Harder to get comfortable with a corporate credit beyond 10 years.

* Local content is an issue

* Limits ability for the developer to seek and get competitive pricing for turbines, because local content limits the number of suppliers you can choose between etc...

* Likes the FIT program

* Reduces the cost / risk of development capital

*What Atlantic Canada can do to encourage renewable development: make sure prices are sufficient. The pool of potential developers in Atlantic Canada is relatively small.

* There is no difference between Atlantic Canada and other places in terms of financing, but the utilities there are smaller and don’t always have a lot of experience buying power under contract.

Interviewee: Senior Power Experts
Interviewers: Ching-yen Chen, Potian, Mitch Rothman, Power Advisory
Subject: Financing Renewable Projects in Atlantic Canada
Date: Nov 29, 2011 @ 2:00 pm (In Person Meeting)
Category: Lender / Debt Capital Markets

* Have not recently raised capital for a renewable energy project in Atlantic Canada, but have raised capital in the region (no issue)

* Have been active in the power sector

* Would expect project sizes would need to be a minimum of $50 mm to get people interested, but that's a rule of thumb (street view). Ability to go smaller sizes on an individual transaction, but that's typically on an expectation of more deals

* Smaller deals ($10 million and up) would be handled by the small/medium business group at the local branch. But local branch lenders would not have wind expertise, and would be referred to the Toronto office

* Toronto office happy to have informal calls with the local branches, but that likely won't be sufficient to get deal across the line. The real issue on getting smaller deals across the line is that the friction costs (e.g. wind studies) would overwhelm small deals

* Like other Canadian banks, we generally do not lend for terms beyond 10 years. For a renewable energy project with a 20 year life, that can create problems because either they have to try to pay off the loan much more quickly from the same cash flow, or they have to refinance

* The number of players looking to be active in this industry is declining, particularly the number of European banks.

Interviewers: Ching-yen Chen, Potian; Mitch Rothman, Power Advisory
Subject: Financing Renewable Projects in Atlantic Canada
Date: Nov 22, 2011 (Phone Call)
Category: Large Developer

* Active developer in the Atlantic region

* See no real issues different in Atlantic Canada than developing wind projects in other jurisdictions, and they have been active nationally and internationally.

* See no difference between Atlantic Canada and other jurisdictions in terms of project attrition. The project in New Brunswick that had a PPA was not specific to Atlantic Canada, but to a federal/provincial issue. Expect project attrition in Ontario also.

* An issue for contracting now in Atlantic Canada is the changing structure in New Brunswick, where NBSO is being folded back into New Brunswick Power.

* The basic problem for renewable development in Atlantic Canada is the size of the market and therefore of the projects. The RFP in Nova Scotia addresses a small market with no transmission access to the United States. A more integrated market would help because, for example, the larger the market the easier it is to balance.

* So not advocating any changes

* Have generally used balance sheet finance, but we see no problems getting project finance in Canada.

* Have not looked at biomass projects in Canada

* Minimum project size: 30 MW. Smaller developers might have more trouble project financing because they lack the track record, but the finance should depend on the economics of the project and on the PPA.

* We like FIT programs, though the current FIT program in Nova Scotia is too small for us.

Interviewers: Ching-yen Chen, Potian; Mitch Rothman, Power Advisory
Subject: Financing Renewable Projects in Atlantic Canada
Date: Nov 22, 2011 (Phone Call)
Category: Small Developer

* Applied to BDC for finance and all local resources (co-ops) for finance for an earlier project in Atlantic Canada, but little knowledge of wind or support

* Went to life companies, but little interest given management's lack of experience at the time

* Unable to finance in Nova Scotia with private funds (amount + term)

  * In theory, wealthy local families could fund but they aren't interested in buying and holding wind assets

  * They could possibly fund a development team (buy-flip model)

* Public / Government funds weren't interested as it didn't meet criteria for job creation (still unclear on why that's the case)

* Currently funded by equity provider which provides equity commitments over construction, no debt until complete. This was especially critical / helpful during the financial crisis (08 – 10)

* Believes it's easy to get financing for $100+mm projects, but much more difficult to get funding for a local developer on COMFIT 1-4 turbine projects where the project size is $5 mm to $20 mm. Financial institutions won't look at them because they are too small. Think a gov't guaranteed loan is the answer. A government guaranteed loan would also simplify the structuring process as friction costs are significant – for example there were five different consultant teams required to review the equity transaction.

* Believes wind projects are fantastic for the local economy as the BOP funds are entirely spent in the local community. Very strong regional support as a result.

Interviewee: Head of Power
Interviewers: Ching-yen Chen, Potian
Subject: Financing Renewable Projects in Atlantic Canada
Date: Nov 24, 2011 @ 9:30 am (In Person Meeting)
Category: Financial investor

* Have looked at projects in Atlantic Canada but found it difficult competing against NSP

* Beneficial that new process is independent of NSP as it was not a level playing field previously given cost of capital advantage

* Do not like contracts where the asset is given back at the end of the PPA; strong preference for retaining rights to the land, etc. (he thought there was a PPA in the region which that was the case)

* Think a co-ordinated and integrated strategy across Atlantic Canada is the answer, easier to enforce a co-ordinated balancing strategy across the ISOs, particularly given the regional generation mix types (nukes in NB, coal in NS, renewables in PEI, etc…)

* Projects tend to be small (20 – 25MW in size), would be more comfortable going into the region with a critical mass of at least 100 MW

* Have not looked at region in any detail recently, but would want to understand the curtailment risks in more detail, particularly in NB, given the large base load supply from Lepreau

Interviewee: Wind Developer
Interviewers: Ching-yen Chen, Potian; Mitch Rothman, Power Advisory
Subject: Financing Renewable Projects in Atlantic Canada
Date: Nov 22, 2011 @ 9:00 am (Phone Call)
Category: Medium-sized Developer

* Charge of renewable development in the NE region

* Sees no difference investing in Atlantic Canada vs other jurisdictions, may even be a little easier as community support is better than some jurisdictions and permitting is easier in New Brunswick, so we have to spend less on pre-approval processes. There is no problem sourcing equipment or finding EPC contracts in Atlantic Canada. When financed in Atlantic Canada, talk to the same people in the same banks in Toronto.

*Generally, the biggest issue for renewable development in Atlantic Canada is the number and size of opportunities for procurement of renewable energy, just one in New Brunswick and one in Nova Scotia. And these are small compared to those in Québec or Ontario just because the markets are smaller. The problem is that each RFP attracts many bidders but produces relatively few winners, and the projects they win tend to be relatively small. So the chances of winning and the rewards of winning are small.

*What would make things easier is a FIT program, even one only for small (10 MW) projects, rather than the RFP where the chance of winning is only 1-5%.

*We would not touch a project of less than 10 MW wind or 5 MW solar unless there is low risk of not getting a contract. We looked at Nova Scotia COMFIT but concluded the projects are just too small.

Local content rules are OK in Ontario because it is large enough to attract the manufacturers.
Will look at projects as small a $25 mm equity cheque

Interviewee: Senior Power Professionals
Interviewer: Ching-yen Chen, Potian
Subject: Financing Renewable Projects in Atlantic Canada
Date: Dec 6, 2011 @ 2:00 pm
Category: Lender

* No problem financing projects in Atlantic Canada, mainly wind and also hydro. Have done it before.

* Size is main driver, hard to look at anything less than $50 mm debt in size. Think this will be hard for anyone to provide such loans on a nonrecourse basis.

* Government support would help but it’s still hard to chase because it's so small

* For it to be considered a non-recourse loan, it would have to very, very close to government debt for it to not be a power project / need to evaluated by the project group

* Key is what's the size, quality, experience of the sponsors? Even if the size is there, developer needs experience to do non-recourse financing

* Concern about lending to biomass projects as they have had a chequered past. Tougher - start-up, supply, and O&M concerns than other technologies

* Expect views to be similar to other banks

* Smaller projects summing to $50 mm in size is, possibly ok, but careful that it's just not 4 separate financings. Much prefer one project of $50mm.

* While $50 mm is a minimum size, sweet spot $100 mm and up, preferably structure 300 to 400 mm, but hold $75 mm or so

* Commonly mini-perm structures - construction + 5/7 (maybe not 10)

* Pricing is ~250 bps, but moving target and unclear the impact will be from turbulence in the European markets. Some are dropping out even when committed. See more impact on term than pricing.

* Focused on wind development in the region. While the company has historically looked at biomass, they are no longer pursuing that.

* If Nova Scotia and New Brunswick were both planning an RFP in the same time frame, it would be an interesting idea to run it jointly and to break it up into 10 MW segments to increase the number of developers who can win.

APPENDIX C: POLICIES FOR LARGER IPPS

Renewables Obligations (Renewable Portfolio Standards)

Renewables obligation programs require a certain fraction of the total electricity supply to be from renewable resources. The requirements are stated as a fraction of the supply at a certain date, often with intermediate requirements. These programs are also called renewable portfolio standards (RPS). In the United States, 29 states have RPS requirements and 8 more have renewable goals. Recent U.S. legislative proposals had provisions for a national RPS program.

The obligation is generally placed on the entities responsible for providing electricity (load-serving entities).[108] They can meet it by producing renewable power or contracting directly with a producer. They can also purchase credits (called Renewable Energy Credits or Certificates, or RECs) from renewable power producers. RPS programs create a separate market for the renewable attributes of renewable power which allows developers to recover a portion of the cost of their projects.

The expectation of RPS programs is that RECs would be priced at the incremental cost of renewable power projects beyond the value of conventional resources. If they are priced below that, the REC value will not be sufficient to allow the project to be financed. If they are priced above that, additional renewable producers will enter the market and create a surplus of RECs.

In the United States, RPS requirements range from 12.5% by 2021 in North Carolina to 33% by 2020 in California.

The important design features of an RPS, in addition to the requirement and timetable, are the definition of renewable resources which can satisfy the RPS, including whether they have to be from within the jurisdiction or not and whether there are any technology carve-outs, requiring some of the renewable energy to come from specified technologies or specified project sizes; whether the renewables muse be procured in certain ways (e.g., only through RFPs); and whether there is an amount that responsible entities can pay if they do not have enough RECs to meet their obligation, which then forms a cap on the price of the RECs.

The effectiveness of an RPS program depends primarily on how much new renewable construction it requires. The programs in California and Massachusetts, for example, have high enough requirements that they cannot be met entirely from in-state resources. They have attracted investment in neighboring jurisdictions, including investment in Atlantic Canada to create RECs that can be sold in Massachusetts.

De Jager and Rathmann[109] conclude that renewables obligations are less effective than FITs in reducing capital cost, because by their nature the value the electricity of the RECs in the market cannot be known in advance. The effectiveness of RPS can be undermined by changes to the resource eligibility requirements. RPS programs are regulatory creations. Changes to these

[108] Power Advisory reviewed US RPS programs for Natural Resources Canada and assessed the potential trade impacts of relaxing provisions in RPS that represent a barrier to trade. "The Potential Impact of Relaxing Renewable Portfolio Standard Constraints on Canada-US Electricity Trade", March 31, 2011.
[109] Op. cit.

regulations, particularly the types of resources that are eligible to participate, create uncertainty, cause prospective participants to be reluctant to participate, and signal to others the risks of participating if rules can be changed that affect the value of the program.

To be effective in Atlantic Canada in removing barrier to the financing of smaller renewable projects, RPS programs would have to carve out requirements for smaller or community-based projects. RPS programs that require RFPs will exclude smaller developers for whom the cost of bidding is prohibitive for an RFP with a highly uncertain outcome.

Production Subsidies

Production subsidies are amounts paid to the generators on the basis of their output. They are stated as an amount per kWh. Such programs are typically funded from general government revenues, though they may be funded from a charge on electricity rates. These policies are reviewed in this Appendix because they have more typically been applied at the federal level and because one application of such policies, production tax credits, is more applicable to larger companies which can take better advantage of the tax benefits.

Canada has had several such subsidy programs. The first was the Wind Power Production Incentive (WPPI), which paid from $.012 to $0.01 per kWh for all output for the first ten years of a project producing wind power. WPPI was replaced by the ecoENERGY for renewables program, which paid $0.01 per kWh for 10 years. No applications for ecoENERGY were accepted after March 31, 2011.

The United States has had similar production incentives, but they have typically been only for limited periods and based on production tax credits (PTC) with renewal dependent on passing new legislation in the Congress.[110] These have created flurries of investment activity as the end of each funding period approached. With *The American Recovery and Reinvestment Act of 2009*, the PTC was expanded to include an investment tax credit and a Treasury Grant given the difficulty of finding investors with tax appetites that could utilize the tax credits generated. The PTC is scheduled to expire for wind projects at the end of 2012 and the Treasury Grant required that projects expend at least 5% of the project cost by the end of 2011. Extension of the PTC is uncertain given fiscal pressures in the US and the current political environment. Recent moves in Congress have created more uncertainty and prompted a warning from the American Wind Energy Association about the economic consequences if the PTC is not renewed.[111]

One disadvantage of the PTC is that it requires taxable income to realize the benefit and project developers typically don't have sufficient income tax liability to fully utilize the PTC. This requires that a party be brought in who has the necessary appetite for these tax benefits. To induce these parties to participate in the project, the developer typically has to provide a sufficient return which leads to discounting the value of these tax benefits. This can result in a loss of value and higher transaction costs which increase overall financing costs.

[110] The PTC is currently about 2.2 cents/kWh for wind projects, almost twice what the ecoENERGY program offered.

[111] American Wind Energy Association, "As wind manufacturing job losses loom, bi partisan wind PTC extension drive continues", press release, Feb. 16, 2012.

The PTC, ITC and Treasury Grants provide US renewable energy projects with a policy-based competitive advantage which must be overcome by renewable energy projects in Atlantic Canada by more favourable renewable resources or lower project costs. Failure to renew the PTC would reduce this advantage.

Production subsidy programs are less effective than FIT programs in overcoming financing barriers. A 10-year production incentive payment lasts only half as long as a FIT contract, and generally half as long as the financing for the project.

The developer still takes the market price risk in a competitive market, unless it has a contracted price. Since the payments are funded from general government revenues, they are vulnerable to cancellation when the government experiences fiscal problems. .

Carbon pricing programs

Programs that increase the price of conventional electricity sources relative to renewable resources provide revenue support by increasing the value of the renewable electricity. A critical issue with the design of such programs is how the carbon price is established: administratively or by a market for carbon. These programs are placed in this Appendix because they generally do not provide sufficient revenue certainty to facilitate financing of small renewable projects.

An administratively determined price could be established by estimating the environmental cost of global warming due to greenhouse gases, i.e., on the basis of damage cost estimates. The carbon price would then be included as part of the price of electricity generated using fossil sources, increasing the market price of electricity in general and therefore providing additional revenue for electricity from renewables, since they have no carbon emissions.

Carbon can also be priced through a cap and trade system or on a market basis, under which emitters are given carbon limits and allowed to purchase allowances from others in the system. A group of Northeastern US states has one such program, the Regional Greenhouse Gas Initiative (RGGI). These states have committed to a schedule of carbon reductions and allocated the reductions among themselves. Carbon allowances are auctioned every three months; the clearing price in all four of the 2011 auctions was US$1.89 per short ton, the minimum allowable bid. These auction results show that CO_2 allowances are not in short supply given reduced electricity demand from the recent recession and lower natural gas prices which is causing some coal-fired generation to be displaced by natural gas-fired generation. At this price, the impact on the competitive viability of renewable generation is relatively small. The RGGI auction price would increase the price of electricity from coal-fired plants by under $2 per MWh, or about 4% of the average electricity price in New England in 2010.[112]

The effectiveness of carbon pricing in promoting renewable electricity therefore depends on the prices for carbon and on the relative costs of renewable and conventional generation. Carbon pricing addresses a global, not a local, problem. Carbon pricing would be most effective as a federal program, but no Canadian federal government has shown interest in a program that prices carbon emissions.

[112] Based on 1999 emissions data, the most recent available, from the US Energy Information Administration of 0.95 tonnes of CO_2 per MWh from coal-fired plants.

To be effective in facilitating finance for renewable generation development, a carbon pricing program would have to provide enough additional revenue and revenue certainty to reduce the risk to the renewable developer and therefore affect financing conditions. As shown by the RGGI experience, carbon pricing programs have not yet achieved that level of price support and price certainty.

Accelerated depreciation

Accelerated depreciation programs reduce the present value of the capital costs by allowing them to be depreciated more rapidly. In Canada, Class 43.1 treatment allows a 30% per year declining balance treatment for the assets, rather than a 6% per year declining balance. In the United States, the 5-year Modified Accelerated Cost Recovery System allows onshore wind energy facilities to be depreciated over 5 years. These programs are included in this Appendix because the proponents of small projects in Atlantic Canada are likely not to have income tax liability (community groups or aboriginal bands) or to be small enough that accelerated depreciation has less financial impact.

De Jager and Rathmann[113] calculate that these programs can be quite effective, reducing the levelized cost of energy in Canada by 5% for the 20 MW wind project that they consider.

For these programs to be most effective, however, the entity owning the project must be taxable and have income subject to tax in the power sector as these programs effectively defer taxes so they do impact government fiscal positions. In the U.S., the impacts of these programs is more significant as investing in renewable generation can be used to offset a corporations' income in other sectors; whereas in Canada the tax benefits must be utilized within the same sector.

[113] Op. cit.