Center for RESOURCE SOLUTIONS

PROJECT DEVELOPMENT AND PUBLIC POLICIES: Feed-in Tariffs, Green Pricing, PBF, RPS

INTRODUCTION

Different policy approaches lend themselves better to some project development approaches than others. In this report, we identify the most common elements of renewable energy (RE) project development, how they have been applied with various types of policy approaches and the critical factors affecting their use. (This paper only deals with larger (1 MW), grid-connected facilities.)

KEY ELEMENTS OF PROJECT DEVELOPMENT

For the purpose of this analysis, *project development* is defined as the process or manner in which a renewable energy generation project is developed and funded. Project development is made up of a number of elements described below.

Financing

The demands of the financial community drive all other considerations of project development. The cost of money to finance a project is directly related to the perceived risk of not having a sufficient revenue stream to recover all of the project costs. If the perceived risks and uncertainties are too great, financing simply will not be available. Common project risks include: equipment performance; accurate resource assessment and resource availability; interconnection, transmission and distribution costs and rules; sanctity of the contract; reliability of the revenue stream; and regulatory and political uncertainty. The lack of experience by a bank with new technologies (like renewable energy) may also make financing from that institution problematic and expensive. The following are the most common methods of financing electric generation projects.

Utility Rate-basing -- A utility-proposed renewable energy project that is to be constructed by the utility with the funds recovered through utility rates is one type of financing model used for project development. In the US this is called 'rate-basing' because the facility costs are embedded in the general rates (or tariff structure) of the utility and are therefore paid for by all of the utility ratepayers. In some cases this may be the least expensive method of financing RE projects depending upon the type of utility, their experience with renewables and the regulatory environment. However under this approach, the risk of non-performance is placed squarely on the utility and its ratepayers so that the utility's actual experience in building and operating such facilities becomes a key factor. Shifting some of the risk to equipment manufacturers or to experienced developers may be critical to project success.

Special Tariff Financing: If a utility is building or buying power from a renewable energy facility that is going to be sold through a special green tariff (e.g. through a green pricing program), the costs are sometimes recovered from only the specific customers who choose to pay directly for the renewable power (often at a premium price above the cost of regular electricity service). The actual facilities may be built and financed by the utility or built by RE developers. These special tariffs may be more risky for the utility since they depend upon the utility doing a good job of educating customers and marketing the power.

Project Financing: An independently developed project (i.e. one not being constructed by the local utility but by an independent company or joint venture) that is offered a utility power purchase agreement (PPA) may obtain project funding based upon the credit worthiness of the utility contract and/or the expected revenue stream of the project from other sources. The developer obtains the financing for the project on their own and recovers the funds through capacity/energy payments as agreed to in the utility power purchase agreement or through sales to retail marketers or wholesale buyers. When the financing is based only upon expected project revenues, and lenders have no recourse other than the project itself, this is called 'project financing.' It is typical to finance projects on this basis with 30-50% equity, and 50-70% debt. A power sales contract with a credit worthy utility in a stable regulatory environment is considered to be essential to reduce risk and financing costs under this type of arrangement. However, the risk of non-performance falls directly on the development company so their experience and past record are important elements in obtaining financing.

Corporate Finance: An independently developed project (i.e. one not being constructed by the local utility but by an independent company or joint venture) may, alternatively, use corporate finance to fund the development and construction costs of a renewable energy project. Unlike project finance, lenders in a corporate finance arrangement can call upon not only direct project revenue but also the holdings of the project owner (equity provider). This can reduce risk for the lender, but places more risk on the project owner. Corporate finance has become an increasingly common way to finance wind power projects in the U.S., and may lower the cost of capital relative to project finance. To ensure a stable revenue stream to service debt payments and meet equity return requirements, a PPA with a utility buyer is a common element of projects funded through corporate finance. However, merchant plants can also be financed on this basis.

Merchant Plant Financing: An independently developed project (i.e. a project proposed to be constructed by an independent company or joint venture) that is being constructed in advance of receiving a complete utility power purchase contract or a project that will sell its power into the wholesale market without major long-term contracts is called a 'merchant plant.' The developer will typically either finance the project itself with internal corporate funds or obtain funds from some type of venture capital or investment banking institution. 'Merchant plants' are the most difficult type of project to finance because they have the greatest risk of not being able to recover their investment costs. Right now in the United States it is virtually impossible to finance a merchant plant.

Ownership
As highlighted by the financing options described above, a power generation facility may be owned by either the utility or by an independent power producer. If owned by the utility, some type of tariff system is generally used to support financing. Utility ownership brings with it the risk of non-performance of the facility; this is a particular problem for technologies with which the utility has had no previous experience. Intermediate ownership options where independent developers with direct experience in building renewable facilities build the facility and then turn it over to the utility to operate at some later time can be used to mitigate some of these risks. These ownership strategies, each with a different risk profile, include: Build and Transfer (BT); Build, Own and Transfer (BOT); and Build, Own, Operate and Transfer (BOOT).

Power Sales
The basis for recovering the costs of developing, building, and operating any power generation facility is the sale of power from that facility into either wholesale or retail electricity markets. The utility recovers the costs of either building a new facility or purchasing power from someone else directly through their electricity rates (either general rates or a special renewable energy tariff). If the facility is not owned directly by the utility company, then some type of long-term power purchase agreement (PPA) is necessary (unless they are able to finance a merchant plant) to ensure the project sponsors and the financing community that the project's revenue will be sufficient to be able to repay its debts including a reasonable rate of return.

Power can be purchased through capacity and energy payments. Where electricity demand is greater than supply, a capacity payment is appropriate along with energy payments. For intermittent resource facilities like wind or solar, capacity payments are generally paid on an as-available basis.[1] Besides price, the key element of any PPA is the clarity of the terms and conditions under which payments will be made and a stable governmental environment that ensures the payments will be made and the contract will not be changed. A 'long-term contract' is usually considered to be between 10 and 30 years in length with a guaranteed purchase price for power at least as long as the period of debt service of the project.

Power Acquisition Process
Because renewable generation facilities are significantly different in both construction and operation from the more traditional thermal or large hydroelectric facilities, they are frequently built and operated by independent power producers who have experience with these technologies rather than by the local utility. The question then becomes the best mechanism for acquiring these resources. The following are some power acquisition methods.

[1] / i.e. The value of the capacity (let's say it is $60/kw/yr) is spread over all the hours in the year (8,760 hrs/year) and paid out in a cents/kWh only during those hours when the facility is generating (as it is available). This capacity payment is in addition to the energy payment that is also paid on a cents/kWh basis.

Fixed-price contracts: When grid-connected renewable resources are in the early stages of development (e.g. there are few local RE development or manufacturing companies and the government is interested in stimulating the development of domestic RE companies and manufacturers), renewables may be purchased using a fixed price and a standard contract (e.g. European feed-in laws, California's standard offer contracts). A standard, fixed-price contract with guaranteed terms and conditions, reduces debt repayment risk and makes it easier to finance RE projects. This is particularly important when the industry is young and immature, financing costs are otherwise high and financing is very difficult to obtain.

Competitive Bidding: Once there are sufficient numbers of RE development and manufacturing companies with actual experience building and operating local facilities, competitive solicitations may be used. There are three primary reasons for using a bidding scheme: (1) to achieve more economic efficiency than is available through fixed-price purchases (i.e., to lower prices); (2) to allocate contracts when there are more potential suppliers than there is need for power; and (3) to identify cost effective resource options that may not have been identified through the resource planning process.

Bidding alone will not necessarily achieve economic efficiency. The goal of achieving economic efficiency assumes that costs (and profits) can be minimized through direct competition among potential suppliers of a product. Economic efficiency is most likely to be achieved when the cost of a product is known with some certainty, when the product is quite uniform and when there are significant numbers of competitors. Competitive bidding does *not* do a very good job of achieving economic efficiency when the final cost of the product is highly uncertain (as when the industry or resource area is new), when there are few competitors, or when there is considerable variation in the product being offered. For contract allocation among potential suppliers, bidding is one of several methods that can be used. Others include: first-come, first-served and a lottery method.

(A separate report on the issues and design of competitive bidding solicitations is being compiled.)

POLICY APPROACHES AND PROJECT DEVELOPMENT

In the following section, key renewable energy policy approaches and the typical project development practices used with each are discussed. We also analyze the critical factors affecting the design and use of these policies.

Mandatory Market Strategies

PURPA Standard Offer Contracts

The Public Utility Regulatory Policy Act (PURPA) is a mandatory market strategy that is price based – utilities are required to buy the power available from renewable resources at the utility's avoided cost of generating or purchasing the power themselves. The PURPA law and the "Standard Offer" contracts were used most notably in California during the 1980s when the renewable energy industry was just getting started. In 1981, when this system was initiated, there were few renewable generators in operation (except large hydro built and owned by the utilities). In fact, Congress passed PURPA for the express

purpose of encouraging the development of non-large hydro, renewable generation by independent power producers (IPP). Since there were few IPP or renewable energy development companies at that time, the State of California enacted policies that would make it attractive for new companies and financial institutions to invest in building and operating renewable energy facilities in the state. The most important policy of the state was to require utilities to purchase renewable generation under a standard offer contract at a fixed price[2] using standard contract terms.[3] Through the use of this fixed price, standard offer contract, almost 5,000 MW of new renewable energy facilities were brought into operation in California between 1983 and 1993.

The success of this strategy was due to the perceived low risk of recovering the project costs during the period of debt service. Moreover, the stable and attractive PPAs allowed projects to attract project-specific debt and equity investors, and project finance was the dominant form of project funding.

In the early 1990s, California issued a Request for Proposals (RFP) for power based on the needs identified through the state's integrated resource planning process (Biennial Resource Planning Update - BRPU). At that point, there had been ten years of experience in California with the building and operation of renewable energy facilities. As a result, RE generators were able to be very competitive in the bidding process with more than 1400 MW of new RE generation bid at prices equal to or less than the California utilities had determined it would cost them to build new thermal facilities.[4] This bidding process was transparent (everyone understood exactly how the bids would be evaluated), and a standard contract with basic terms and conditions was used as the basis for the bids. Bids were received for more than three times the amount of power actually needed.

A primary problem with the California system was that there was no limit put on the amount of power that would be purchased at the fixed price. Once the system reached equilibrium (i.e. supply was sufficient for the demand), the value of new generation was less, however, there was no mechanism to reduce the price. Moreover, once a significant RE industry was established in the state, it was possible to purchase RE at a lower price than what had been originally set. However, the system had no mechanism to take advantage of these cost reductions until it went to a competitive bidding process with the BRPU.

---

[2] / Since these contracts were signed during a time when there was a shortage of power in California, the generators were paid a fixed capacity price as well as a kWh price for energy. The fixed energy price actually only pertained to the first one third of the contract life (i.e. 5 to 10 years for 15 to 30 year contracts). The energy price during the last two thirds of the contract term was to be whatever the wholesale market price for energy was at that time. The fixed-price was calculated based on the avoided cost of what it would otherwise have cost the utility to build or buy that power themselves as indicated in their resource planning process.

[3] / The standard offer contract is a default contract that does not have to be negotiated with the utility unless the developer needs some special term or condition. The purpose of this strategy was to eliminate the absolute power of the utility in a contract negotiation and put the two parties on a move even footing.

[4] / Unfortunately, these projects were never built due to restructuring of California's electricity sector.

Feed-in Laws

Feed-in laws are a similar price based policy to the one described above for California. They have been most successful in Germany, Denmark and Spain. They were initially designed at the beginning of renewable energy industry development in those countries just as in California. Their purpose, as in California, was to stimulate the development of new domestic RE companies and facilities. The primary difference was that the fixed price paid in the feed-in laws has often been based on a percentage of the retail electric tariff rather than being based on the wholesale cost of power to the utility as it was in the US. Just as in California, however, these feed-in laws have resulted in thousands of MW of renewable generation being brought into operation in a very short period of time in the countries that adopted them. The feed-in policies also stimulated the growth of a domestic RE industry in both countries. The success in bringing large amounts of RE into operation can be attributed to both the attractive fixed price[5] and the stability and governmental guarantees that ensured the payments would be made. This reduced transactions costs and minimized any perceived risk, making investments in new renewable energy development very attractive to the European investment community. Renewable energy investments have come in the form of project finance, as well as more traditional cooperatively financed or individually owned projects.

Some of the feed-in laws in Europe were structured similarly to the CA standard offer such that they were unable to take advantage of market efficiencies. However, there have been fewer traditional resource technologies competing with the renewables and the policies have been amended over time to take advantage of falling costs for specific RE technologies.

Non-fossil Fuel Obligation (NFFO)[6]

The Non-fossil Fuel Obligation is a hybrid policy that is both price and quantity based. The UK NFFO Policy implemented competitive bidding orders for renewable electricity designed to bring on-line 1,500 MW of new renewable capacity, roughly three percent of the total UK electricity supply, over a ten-year period. As with the 1980s California Program and the1990s feed-in Laws in Germany, Denmark and Spain, the 1990 UK NFFO policy was developed before any RE industry had been established in Britain. As a result, there were few local competitors available to bid for the government RE purchases. Moreover, there were few penalties for non-performance. Therefore, though the NFFO bidding process produced amazingly low bid prices for RE facilities, the policy resulted in only 21 percent of the projects actually becoming operational.[7]

---

[5] / Approximately 8 cents/kWh – about the same as the fixed energy prices for the early California projects.

[6] / The non-fossil fuel obligation was implemented in the UK in 1990. It began with fixed price payments for a specific quantity of RE but then moved to a bidding system for acquiring the appropriate supply. The money to pay the difference between the average wholesale cost of power and the cost of the renewables was collected through a special levy on electricity from fossil plants.

[7] / This was as of a report at the end of 1999: Mitchell, C. "The UK Non-Fossil Fuel Obligation: History and Lessons." *Annual Review of Energy,* December 1999. Mitchell, C. "Renewable Energy Policy in the UK – Obligation Options for the Future." Paper for the UK Department of Trade and Industry. Brower, Michael C.,"The British Electric Utility Restructuring Experience: History and Lessons for the United States." The Electric Industry Restructuring Series, National Council on Competition and the Electric Industry, 1996.

Because of its focus on cost reductions, the NFFO did not support a diverse set of renewable developers. There were few new, local entrants into the UK renewable energy market. The majority of NFFO power plants are owned by subsidiaries of the major generators, the retail electricity companies, or subsidiaries of privatized water companies. Because of the pressure to reduce costs, corporate finance has been the most common financing arrangement. More importantly, the NFFO did not create any kind of enhanced domestic manufacturing base for renewable technology. This is because in order to win an NFFO contract, the cheapest technology must be used and this tended to be from non-British sources.

In this example, all the elements were in place as required by the financial community (e.g. a guaranteed price, a long-term contract -- 15 years). However, using a competitive bidding acquisition strategy did not result in the development of a domestic RE industry infrastructure. As a result, the NFFO did not lay a sustainable framework for development of RE in Britain.

Renewable Portfolio Standard (RPS)[8]

The Renewable Portfolio Standard is a quantity based mandatory portfolio policy where the RE price varies with market demand. The interaction between RPS and project development is not entirely clear due to limited experience with fully implemented RPS programs. In Texas, where we have the most RPS experience to date, RE development has moved forward rapidly. This is partly due to the utilities, who are required to meet the mandatory targets, signing long-term contracts (10 to 25 years) for RE. These utilities issued RFPs and selected the bids offering the best prices and the highest likelihood of bringing the project to completion on schedule. These tended to primarily be bids for power from new wind projects that when they took into consideration the 1.5 cent US/kWh production tax credit, caused the wind prices to be almost as low as power from conventional plants. Wind power plants were constructed based on both corporate- and project-finance structures.

In addition, a robust competitive retail green market (and green pricing markets for the municipal utilities that have not been restructured) offers a variety of opportunities for RE in the state as well as in the region. All of this makes for attractive project financing for independent RE developers with power sales contracts. We expect a similar pattern to develop in other states but we do not have sufficient information to know yet.

[8] / A Renewable Portfolio Standard is a policy that mandates a specified amount of power to be supplied by RE. These programs have been approved in 13 US states, Australia, Belgium, Italy and the UK. Sweden and Norway are also considering passage of an RPS mandate but it is still in the talking stage. For more information and background on the issues see papers prepared for China by Jan Hamrin and Ryan Wiser for the China Sustainable Energy Project and Ryan Wiser and Ole Langness, *Renewable Portfolio Standard in Texas: An early assessment.* LBNL-49107.

The sale of tradable renewable certificates (certificates) separate from the energy output of a renewable generation facility is an interesting outgrowth of the RPS concept. Though in the Texas example the RE power and certificates have often been bundled together, in other US states and Europe, certificates are also being sold separate from the power (particularly to larger commercial and industrial customers) as well as being converted into carbon emission offset credits. What this means for the development and financing of new RE projects is that there may develop an alternative revenue stream to support project finance. Though the market for certificates is new and uncertain at present, in the future this could become an important RE project element.

Customer Choice Policies: Green Pricing[9] and Green Markets[10]

The resource acquisition process associated with customer choice programs is more variable than for other policy strategies. Since the renewable power is offered to the customers by their monopoly utility provider, the utility may (1) build the RE facilities themselves, (2) go out to bid for a 'turnkey' project that they eventually own or (3) buy the power from an independent producer. In this last case, the RE utilities or marketers usually either buy excess RE from facilities that have already been built but that have excess power beyond what is being sold under utility supply contracts or have been able to increase generation at an existing facility to serve the green market. All three processes have been used with varying success depending upon the circumstances.[11] New facilities are typically only built once a contract has been signed with either a utility or a marketer for the majority of the facility's anticipated output. Though merchant plants could be built to serve these markets, generally the risk and uncertainty are too great to allow them to be financed.

In the US, about 650 MW of new RE has been constructed and another 440 MW of new RE is under construction specifically to serve the US green customer choice markets . With both of these types of green programs, they were developed after there was an established RE industry in the US with plenty of competitors to provide the RE supply. Financing and building RE facilities for competitive green markets is more risky than with a utility long-term power purchase agreement since neither green marketers nor utility green pricing purchasers tend to sign contracts for longer than five years. However, depending upon the extent of the future local market opportunities, a five-year, guaranteed price contract in a maturing RE industry may sometimes be sufficient to support new RE development. All the examples we have to date indicate that new RE development under this scenario will be much slower than under standard contract or feed-in law strategies.

---

[9] / Green Pricing is where a monopoly utility offers its customers the choice of renewable energy or conventional energy, with the RE option often costing more than the conventional.

[10] / This refers to the 'direct access' programs in reformed electricity markets where customers have both the choice of the company who will supply their power as well as the type of power they will buy (e.g. Renewable resources).

[11] / For a good discussion of the advantages and disadvantages for utilities of buying versus building RE facilities see Mark Bolinger, Ryan Wiser, and Bill Golove *Revisiting the "Buyversus Build" Decision for Publicly Owned Utilities in California Considering Wind and Geothermal Resources. LBNL-48831, October 2001.*

Investment Incentives and Funds

Public Benefit Funds[12]

In the United States there are 14 states with Public Benefit Funds used wholly or in part for supporting renewable energy development. These funds have most often been developed in conjunction with the reform of the electricity sector in that state but they can also be used under traditional utility structures. In the US, they were all developed after there was a well established RE industry. States are adopting a wide variety of approaches to using these funds. Two states are using funds to provide low-interest loans in an investment model approach. Seven states are using the funds as financial incentives, either as production incentives or grants to directly stimulate renewable energy project installation by reducing the costs.

Building industry infrastructure is especially important where limited renewable energy project experience exists. Three states are offering business development grants; two states are providing funds for consumer financing programs; four states are providing funds to support renewable energy marketing; two to support broad-based consumer education; and two states are using funds for detailed resource assessment.

These funds have achieved their most visible success in providing funding for large-scale renewable generation projects. It is possible that more than 1,100 MW of new RE capacity will be installed over the next few years as a result of these clean energy investments. Most states have used competitive bidding mechanisms to solicit project proposals and to determine how financial incentives will be distributed (particularly for large, grid-connected projects). Most of the financial incentives are provided through some type of performance-based program. Finally, to maximize the impacts of their efforts, state PBF administrators are exploring the interactions between their own funds and other RE programs including state RPS policies, tax credits and various regulatory rules.

These funds can be particularly valuable in supporting the development of a local RE industry and in reducing the overall cost of RE so it is more competitive with the cost of conventional technologies. Such incentives will not achieve their goals unless they are tied to policies and programs that provide a reasonable price for power through a medium to long-term power purchase agreement. In California, though funds have been awarded to 1300 MW of potential new RE projects between 1998 and 2001, only 200 MW of those projects have actually been completed primarily due to the lack of a power purchase agreement from a credit worthy utility purchaser (thus making it impossible to get project financing).

[12] / Public Benefit Funds are pots of money collected through a small surcharge on electricity sales and used exclusively for funding public interest programs in electricity such as renewable energy, energy efficiency, research & development, and low-income family assistance. For an excellent overview of these funds see Mark Bolinger and Ryan Wiser, et. al. *Clean Energy Funds: An Overview of State Support for Renewable Energy,* LBNL – 47705, April 2001.

Tax Policies
Beneficial tax policies of various types can be very useful in conjunction with other RE policies. To the extent that favorable tax policies reduce the cost of the renewable energy facility, they help make the facility more cost competitive with traditional power generation technologies. However, favorable tax policies are not typically sufficient in themselves to justify financing and building a new RE facility. There must be the ability to sell the power that is generated into an electricity market. In addition, it is necessary to be able to interconnect the facility to the transmission/distribution system under conditions that do not jeopardize the payments for power or the overall project revenue stream.

Public Education
Though RE public education programs are extremely important, as with the tax policies discussed above, they have only a secondary effect on the ability to finance and build RE facilities. To the extent that public education programs educate public officials and help to mobilize public support, they can lay the groundwork for good public policy and for a receptive competitive market.

CONCLUSIONS

Because the needs of the financial community so strongly influence RE development, any policies or programs that reduce the cost of RE facilities, or reduce the perceived risks of not receiving an adequate revenue stream, will make financing easier and less costly.

Mandatory market strategies build a market for renewables while reducing the transactions costs and risks associated with early commercialization of RE. Standard-offer contracts and feed-in laws are excellent tools for rapidly mobilizing the renewable energy industry in a new region. They are easily implemented under any industry model and will result in a lot of renewable generation coming into operation rapidly. Once a RE industry is established, competitive bidding processes can be used to obtain more economically efficient results.

An RPS policy is also designed to quickly develop a market for RE, though RPS programs require very careful design and implementation to achieve their goals. Because the price for the RE is uncertain under an RPS structure, project development and financing may be less attractive under this policy than it is under a standard-offer contract or feed-in law approaches. An RPS policy may also require a stronger legal system and stable electricity regulatory framework than other policy approaches.

Most renewable energy projects are built by independent power producers (IPP) rather than by the local utility. As a result, support for IPPs is critical for renewable energy industry growth. Such policy support includes a reformed utility structure that allows independent producers to build, own and operate renewable energy facilities, interconnect to the grid, and provides guidelines favorable for the pricing and purchase of the power from these facilities by the electric company. Other important supporting policies include tax incentives, standard contracts, resource assessment and equitable resource laws, and fair and reasonable interconnection and transmission rules. Renewable energy costs are typically lowered through manufacturing volume, renewable energy industry

infrastructure development and project development experience. These cost reductions can only be realized from the development of a robust market for renewable energy.