Regulator's Handbook on
Renewable Energy Programs & Tariffs

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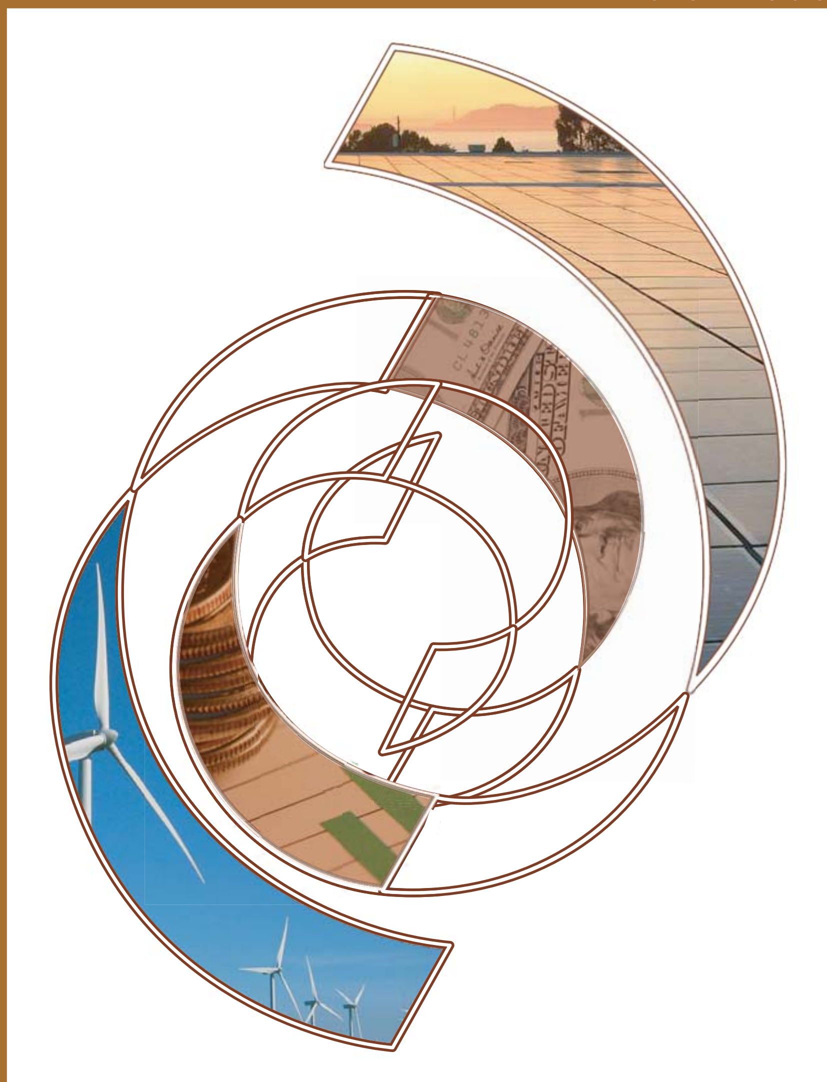

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About The Center for Resource Solutions

The Center for Resource Solutions (CRS) is a non-profit organization focused on energy and environmental issues. CRS is based in San Francisco and administers programs in the U.S. and abroad that promote renewable resources, encourage energy efficiency, and help speed the growth of cutting-edge clean energy technologies. The largest program at CRS, the Green-e Renewable Energy program, focuses on customer choice of renewable electricity, both in competitive and monopoly retail markets. www.resource-solutions.org

TABLE OF CONTENTS

Acknowledgements i
Table of Contents ii
Executive Summary 1
I. Introduction 5
II. Voluntary Customer Mechanisms 7
- A. Green Pricing 7
  - Program Details 9
  - Best Practices 10
  - Successful Programs 13
  - Conclusion 13
  - References 14
- B. Check-Off Programs 15
  - Background 15
  - Program Details 15
  - Supplier Qualifications 17
  - Product Qualifications 18
  - Requests for Proposals 18
  - Program Cost Recovery 19
  - Summary of Best Practices for Green Check-Off Programs 19
  - References 20
- C. Community Aggregation 21
  - Background 21
  - The Motivation for Community Aggregation 22
  - Program Details 23
  - Metrics of Success 24
  - Best Practices 25
  - Conclusion 27

III. Mandatory Mechanisms 28
- A. Renewable Portfolio Standard (RPS) Laws 28
  - Background 28
  - Program Details 29
  - Best Practices 35
  - Conclusion 37
  - References 38
- B. Public Benefits Funds 39
  - Overview 39
  - Program Details 39
  - Metrics of Success 42
  - Best Practices 43
  - Conclusion 45
  - References 46

C. Net Metering 49
Overview 49
Program Details 51
Metrics of Success 53
Best Practices 54
Conclusion 55
D. The Interaction of Green Tariff Programs: Avoiding Double Counting, Improving Results.. 57
Interaction of Green Tariff Programs 57
Program Selection Process 57
Avoid Double Counting 58
Best Practices 59
Conclusion 59
IV. CASE STUDIES 61
Case Study: Model Green Check-off Tariff 61
Case Study: Model Green Pricing Tariff 64
Case Study: Model Renewable Portfolio Standard 66
Case Study: Model Public Benefits Fund 68
Case Study: Model Net Metering Rule 71

TABLES AND TEXT BOXES

Table 1. State Green Pricing Mandates……..8

Text Box: Promoting Community-Based Renewable Energy…… 24

Text Box: Incorporating Certification and Verification Costs into Voluntary Market Programs………. 27

Text Box: The "No Tariff" Approach to Renewable Energy……. 28

Text Box: REC Tracking 101……..30

Table 2. State RPS Program Cost Recovery Summary……...31

Table 3. An Overview of Renewable PBFs in the United States…….40

Text Box: Public Benefit Funds & REC Ownership……..47

Table 4. Summary of Net Metering Rules……...50

Text Box: California's Carbon Risk Adder…….51

Text Box: Washington State's Feed-In Tariff……..58

Text Box: Taking RECs in Exchange for Financial Incentives……...62

Case Study Table 1. Comparison of the Reallocation of Funds Between 1998 and 2002……...71

EXECUTIVE SUMMARY

Renewable energy markets are surging, due to volatile natural gas prices, California's energy crisis, concerns about energy security and energy independence, improving technology, declining costs, and increasing environmental awareness. In the United States, much of the trend is occurring in the electric utility sector, stimulated by regulatory policies and programs at the state level. These programs may be voluntary or mandatory. Voluntary programs include green pricing, check-offs, and community aggregation. Mandatory programs include renewable portfolio standards, public benefits funds, and net metering.

This handbook is for regulators involved in the design of renewable energy programs, with a focus on tariffs. It suggests best practices for renewable energy program design and tariff setting and highlights successful renewable energy programs in a series of case studies. This handbook is divided into sections that can be read sequentially or referred to individually when particular issues arise.

This Handbook contains the recommended best practices and the authors' best thinking given their experience to date with renewable energy programs. The best practices contained in the Handbook came from a variety of sources including interviews with utility representatives, regulatory staff and other experts; practices commonly adhered to by market participants; National Association of Attorneys General Environmental Marketing Guidelines; and the author's opinions based on all of the above and generally held tenets regarding consumer protection and green power marketing. In some cases, there are topics where specific regulatory best practices or principles are still being developed. Other issues may be very sensitive to local conditions, so beyond key principles, no specific recommendations can be made.

Each section of the handbook is complete as a reference guide for each topic. Each section begins with a discussion of issues and concludes with a summary of recommended best practices. Most sections also contain a list of informational references and a text box on a related topic. The handbook concludes with a series of case studies on five of the topics covered in the handbook.

Green Pricing (pages 7-14)

Green pricing, which may be required by statute, allows electric utility customers to choose to purchase some or all of their power from renewable energy technologies such as solar, wind, geothermal, small hydropower, and biomass. This choice usually costs extra.

Green pricing options include: fixed quantity block, percentage of monthly use (up to 100%), generation charge, capacity-based block, fixed fee, or contribution to a fund.

Because green pricing participation is voluntary, regulatory oversight is usually light. Green pricing programs should be: simple, marketable, effective, economical, and accountable. This section addresses best practices in green pricing that help meet those goals.

Check-off Programs (pages 15- 20)

In a green power check-off program, a customer makes a voluntary purchase of Renewable Energy Certificates (RECs) from a third-party supplier as an add-on subscription to existing electricity service. This is different from green pricing programs in that the customer makes the purchase of RECs from a utility-approved third party supplier, rather than from the utility itself. The customer's electricity needs continue to be met by his/her traditional supplier.

Because a check-off program is not a renewable electricity service per se, there may be no regulatory tariff. However, check-off program rates are typically determined through a competitive solicitation and this section of the report focuses on best practices in selecting one or more suppliers.

Community Aggregation (pages 21-27)

Community aggregation is when a local government aggregates the loads of electric service customers within its jurisdictional boundaries and provides electricity and other energy services to meet those loads; it is an alternative to the electricity service provided by the retail utility (or standard offer service). Community aggregation can offer a creative, effective, and economical way of bringing renewable energy and energy efficiency services to communities.

A local government community aggregator does not become a municipal utility and does not own and operate transmission and distribution systems. Rather, it procures electric power from the wholesale market, which is delivered to end use customers by the local transmission and distribution utility. Billing may be provided jointly with or by the utility.

Community aggregation customers are usually acquired through an 'opt-out' process, i.e. everyone within the jurisdictional boundary is in the program unless they indicate they want to opt-out. This section of the report focuses on the rules regulators should adopt in order to meet best practices in community aggregation.

Renewable Portfolio Standards (pages 28-38)

A Renewable Portfolio Standard (RPS) requires a utility to have a percentage, usually growing over time, of its supply portfolio consist of renewable resources. The RPS is generally intended to create a stable and predictable market for renewable electricity that maximizes the benefits of renewable generation while minimizing costs.

RPS features vary from state to state with respect to:

- target level,
- whether the target is based on percent of energy sold or installed capacity,
- dates when targets must be met,
- resource eligibility,
- scope of geographic eligibility,

- preferential policies to encourage particular types of renewable energy, such as specific resource targets or multipliers,
- limits on costs or cost recovery,
- penalties for non-compliance, and
- whether RECS can be used, and/or whether power must be purchased.

This section of the report focuses on RPS best practices regulators can employ to meet the goals of the program.

Public Benefits Funds (pages 39-46)

A public benefits fund (PBF) is a revenue stream most commonly financed through an ongoing surcharge on consumer electric bills (e.g., a "green tariff"), but also occasionally established through lump-sum cash transfers required by state legislation or regulatory settlements. It is used to directly support projects and activities in the electricity sector that provide important public benefits or overcome market barriers.

Many states created renewable PBFs to help protect, preserve, and grow nascent renewable energy markets that might be in jeopardy as the electricity industry was restructured. In other states, PUCs have authorized the creation of renewable PBFs or they arose from utility merger or environmental settlements.

Renewable PBFs have supported a wide variety of programs, including:

- financial incentives for large-scale projects,
- rebates and buy-down incentives for distributed generation,
- consumer loan programs,
- project and company financing,
- support for green power marketers,
- consumer education, and
- small grants for business development, feasibility studies, workshops, conferences, and other activities.

This section of the report focuses on best practices in PBF creation, determination of programmatic scope, and PBF administration.

Net Metering (pages 49-55)

Net metering, for consumers with generators on their side of the meter, allows electricity to flow in either direction through a bi-directional meter. When the customer's generation exceeds his/her use, electricity from the customer's facility flows into the utility's distribution grid and its quantity accumulated in the customer's account.

Net metering has many purposes:

- promoting small-scale renewables,
- enhancing the market for renewables,
- facilitating installation and interconnection of on-site generation,
- reducing customers' electricity bills,
- empowering customers to manage their electricity usage, essentially storing excess power on the grid for use at a later time, and

- lowering the utility system peak demand, and
- reducing environmental impacts.

A key feature of net metering is the ability to virtually store excess power that is generated by the customer's facility on the grid until it is needed, for a period that varies from one month to indefinitely, but usually for one year. At the end of this period the account balance may be zeroed (i.e. the utility gets the surplus power for free) or the customer may be paid at a rate that varies from avoided cost to full retail price.

This section of the report focuses on common misconceptions about net metering, and also covers best practices related to net metering.

I. INTRODUCTION

Regional and national renewable energy markets in the U.S. and worldwide have surged in recent years due to: volatile natural gas prices, California's energy crisis, concerns about energy security and energy independence, improving technology, declining costs, and increasing environmental awareness. According to Clean Edge, a research and publication firm, solar and wind power generation capacity in the U.S. have each grown by an average of more than 30% annually over the past five years.[1] The use of geothermal and biomass energy to generate electricity has also advanced at respectable rates in the past decade. This trend is likely to continue for the next decade given the passage of 21 state Renewable Portfolio Standard laws (and several more pending), the continued popularity of green power purchasing programs, and other voluntary and mandatory renewables programs. However, how much growth is realized, and how efficiently and economically it is achieved, is in great part in the hands of electricity regulators.

The states, through electric utilities and their regulators, have the power to substantially affect the renewable energy industry. State policies that encourage the use of renewable energy include: renewable portfolio standards, net metering, public benefits funds, green power purchasing programs, and outreach and educational activities. Renewable energy tariff-setting is a key component to the success or failure of these policies. Fortunately, there is now a case history of renewable energy program implementation and related tariff-setting from which to draw when considering how best to promote renewable energy through regulatory ratemaking and tariff setting at the state level.

The report writers researched each topic through dozens of interviews with regulators from coast to coast.

This report is designed to be a resource for regulators who are involved in the design of renewable energy programs, with a focus on tariffs. It addresses electricity tariffs for renewable energy programs, suggests best practices for renewable energy tariff setting, and highlights successful renewable energy programs in a series of case studies. The best practices suggested in this handbook can maximize the use of renewable energy in the most cost-effective manner by providing guidance to regulators interested in renewable energy.

The report does not cover tax credits, because utility regulators do not set tax policies. Nor does it cover most issues related to Renewable Energy Certificates (also known as Tradable Renewable Certificates or Green Tags). Those issues are covered in the CRS authored Regulator's Handbook on Tradable Renewable Certificates.[2]

[1] Clean Energy Trends 2004. http://www.cleanedge.com/reports/trends2004.pdf
[2] http://www.resource-solutions.org/RegulatorHandbook.htm

In many cases, the advice given here, usually called "best practices," could be useful either to utility regulators or state legislators, depending on how prescriptive legislatures chose to be and how much implementation discretion statutes give regulators.

II. VOLUNTARY CUSTOMER MECHANISMS

This section covers policies and programs used by customers on a voluntary basis in an electric utility framework. These include utility green pricing programs and green check-off programs offered by third party suppliers.

A. Green Pricing

Green pricing, a voluntary option offered by electric utilities, allows customers to support new investments in renewable energy technologies such as solar, wind, geothermal, small hydropower, and biomass. Green pricing customers, an increasing percentage of whom are non-residential, may be motivated by their desire to reduce pollution, combat global warming, increase energy security, stabilize their energy costs, improve their public image, or other reasons. Generally, this environmentally preferable electricity costs a little more than traditional power generated from sources such as coal, natural gas, large hydropower and nuclear fuels. Green pricing customers pay a green rate (typically at a premium above the cost of regular electric service) on their electric bills to cover the higher cost of renewable energy.

Because green pricing programs have traditionally been established voluntarily by utilities, there has been a relatively low level of regulatory oversight. However, five states have enacted legislation (Iowa, Minnesota, Montana, Washington) or issued regulations (New Mexico) mandating that green pricing options be made available for customers.

Table 1. State Green Pricing Mandates

State	Summary of Rule	Program Details Related to Tariff
Iowa[3]	Utilities shall offer an alternate energy purchase program to customers, based on energy produced by alternate energy production facilities in Iowa.	Rate-regulated electric utilities shall file plans for alternate energy purchase programs that allow customers to contribute voluntarily to the development of alternate energy in Iowa and shall file tariffs as required by the board by rule.
Minnesota[4]	Each utility shall offer its customers, and shall advertise the offer at least annually, one or more options that allow a customer to determine that a certain amount of the electricity generated or purchased on behalf of the customer is renewable energy or energy generated by high-efficiency, low-emissions, distributed generation such as fuel cells and microturbines fueled by a renewable fuel.	Rates charged to customers must be calculated using the utility's cost of acquiring the energy for the customer and must: (1) reflect the difference between the cost of generating or purchasing the renewable energy and the cost of generating or purchasing the same amount of nonrenewable energy; and (2) be distributed on a per kilowatt-hour basis among all customers who choose to participate in the program.
Montana[5]	A default supplier (utility) shall offer its customers the option of purchasing a product composed of or supporting power from certified environmentally preferred resources that include but are not limited to wind, solar, geothermal, and biomass.	Subject to review and approval by the commission.
New Mexico[6]	Each public utility shall offer a voluntary renewable energy tariff for those customers who want the option to purchase additional renewable energy.	The tariff, along with the details of the consumer education program, shall be on file with the commission.

Table continues on next page

[3] http://www.legis.state.ia.us/IACODE/2001SUPPLEMENT/476/47.html
[4] http://www.revisor.leg.state.mn.us/stats/216B/169.html
[5] http://www.montanagreenpower.com/greenpower/legislation.html
[6] http://www.nmcpr.state.nm.us/nmac/parts/title17/17.009.0572.htm

Table 1. State Green Pricing Mandates (continued)

State	Summary of Rule	Tariff Details
Washington[7]	Each electric utility must include with its retail electric customer's regular billing statements, at least quarterly, a voluntary option to purchase qualified alternative energy resources.	The option may allow customers to purchase qualified alternative energy resources at fixed or variable rates and for fixed or variable periods of time… The rates, terms, conditions, and customer notification of each utility's option or options offered in accordance with this section must be approved by the governing body of the consumer-owned utility or by the commission for investor-owned utilities. All costs and benefits associated with any option offered by an electric utility under this section must be allocated to the customers who voluntarily choose that option and may not be shifted to any customers who have not chosen such option. Each consumer-owned utility must report annually to the department and each investor-owned utility must report annually to the commission … describing the option(s) it is offering its customers, the rate of customer participation, the amount of qualified alternative energy resources purchased by customers, the amount of utility investments in qualified alternative energy resources, and the results of pursuing aggregated purchasing opportunities. The department and the commission together shall report annually to the legislature with the results of the utility reports.

Program Details

Product Pricing Options: There are several product options for utilities and their PUCs to consider when designing products prices, and billing systems. The following are most common.

- **Fixed Quantity Block**: The utility sells blocks, for example 150 kWh, of 100% green power for a premium per month, say $4. Customers may sign up for as many blocks as they wish. Accounting is easy because customer metering data are not required.

- **Percent of Monthly Use**: A customer may choose green power to supply some percentage, say 25%, 50% or 100%, of his/her monthly electricity use, typically at a premium on a cents per kWh basis. Billing is done as a line item multiplier of the monthly consumption.

- **Renewables as Generation Charge**: A customer pays a fixed charge per kWh to purchase the generation portion of their supply from renewables. The regular generation rate per kWh is replaced by a green power rate. The green power customer is unaffected by changes to variable fossil fuel rates.

- **Capacity Based Block**: A customer signs up for one or more capacity blocks, e.g. 200 watts of solar PV capacity each month. Customer metering data are not needed.

[7] http://www.leg.wa.gov/RCW/index.cfm?section=19.29A.090&fuseaction=section

- **Fixed Fee**: A customer signs up for a dollar amount, e.g. $5, of green power each month, for a specific percentage of their monthly use that will be matched with renewable energy. This is similar to the fixed quantity block, but no pre-determined MWh guarantees of power delivery are made. Billing is simple, but utilities will not know in advance how much energy they will need to meet demand.

- **Contribution**: A customer donates an amount, e.g. $5, per month to go into a renewable energy development fund. As opposed to a fixed quantity block, which delivers a specified quantity of renewable energy to the grid in exchange for the customer payment, or a percent of monthly use which delivers a specified portion of renewable energy to the grid, a contribution program does not make any specific promises of renewable energy production. Disbursement of the fund is at the discretion of the utility. Billing is simple, but customers do not necessarily know what they get for their premium payment.

There is no optimal pricing structure, but PUCs should consider these design criteria:

- **simplicity** of product design, so customers understand what they're getting;
- **marketability**, so it is as easy as possible to sell the program;
- **effectiveness**, i.e. actually producing more green power than would otherwise have been produced consistent with customer demand;
- **cost**, program costs must be reasonable and reflect program benefits; and
- **accountability**, how the program is reported to the PUC and how costs are recovered.

Most customers say they are willing to pay a premium of five dollars per month for green power, but this willingness drops steeply above that amount.[8] The median green pricing charge is about 2.5 cents/kWh. Offering customers a series of price points (options such as 50% or 100% renewable, or buying any number of 150 kWh blocks, for example) will broaden access to the program because some customers are willing to pay more than others for green power.

Best Practices

In the past, Commissions have sometimes felt it was sufficient to simply ensure that costs from green pricing programs were not being subsidized by non-participants. However, Commissions can go further by ensuring green pricing programs are providing real value to utility customers and that the pricing not only avoids cross subsidies but is also cost reflective. The following are some best practices for green pricing programs.[9]

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[8] Farhar, Barbara C. "Willingness to Pay for Electricity from Renewable Resources: A Review of Utility Market Research". National Renewable Energy Laboratory. NREL/TP.550.26148. July 1999. Florida Power & Light's fixed price block product at $9.95 per month has been successful in signing up over 10,000 customers and is now ranked 10th by National Renewable Energy Laboratory in number of green pricing participants.

[9] For details on additional best practices in green pricing, such as product design, marketing practices, and working with stakeholders, see "Green Pricing at Public Utilities: A How-to Guide Based on Lessons Learned to Date." http://www.resource-solutions.org/lib/librarypdfs/PRP.Green.Pricing.Report.10.29.02.pdf

Support new renewables.
Green pricing products should be developed specifically to serve the voluntary purchases. The use of renewable energy from "new" facilities will make the program easier to market and ensure the customers' money results in additional renewable energy that would not otherwise have been produced.[10]

Allow all customers to participate.
A utility should offer the product to all customers in all regions and all classes (residential, commercial, and industrial). If the program is unsuitable or unattractive for any customers, it should be they who decide rather than the utility deciding for them.

Support an adequate marketing budget.
Customers need to understand their choices in order to exercise them. In 2004 utilities reported that a median of 8.5% (average of 20%) of the total green power premium was spent on marketing and program administration; the top performing programs spent a median of 25% and an average of 28%.[11]

Require adequate disclosure.
Ensure that adequate information is provided to customers about the source of the renewable energy, purchase terms, and a comparison of the green power mix with the mix of energy sources used by the utility for all customers. This contributes toward the customer being able to make an informed choice.

Sell renewable energy for price stability.
Unlike some conventional energy resources whose costs vary with the fluctuations of fuel input prices, renewable energy sources can typically be purchased by utilities at fixed and known prices. Austin Energy, Oklahoma Gas & Electric, Xcel Energy, and Eugene Water & Electric Board have used this natural characteristic of renewable energy and used price stability as a key selling point for their products, especially when marketing to non-residential customers. Austin Energy's green price is not a premium added to the customer's rate, but rather is a stand-alone renewable energy rate that replaces the standard tariff. The renewable energy rate is guaranteed to be stable for ten years. In contrast, Austin Energy's non-green customers are exposed to adjustments in fossil fuel rates. For details, see the case study on page 64 of this report.

Austin's Green Choice charge has at times been higher than, and at times been lower than, the non-Green fuel charge, but has always been less volatile. Because the forecast prices of non-renewable fuels have been high, Austin Energy customers may hedge their utility bills by signing up for a fixed-rate tariff from renewables. Regulators can encourage green pricing program providers to exempt participating customers from fossil-fuel cost adjustments that are specifically related to the use of non-renewable fuel sources on a pro-rata basis in relation to the amount of renewable energy purchased by the customer.

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[10] "New" is generally defined as power from renewable energy projects that became operational after the date of the green-pricing program or some other recent date.
[11] http://www.eere.energy.gov/greenpower/resources/pdfs/38800.pdf

Renewables for green pricing and renewables for mandate compliance should be separate.
If facilities that are being paid for by the general rates are used to supply a voluntary program, green pricing customers will be paying a premium for power the utility would have been purchasing anyway. The same principle applies to renewable energy used to satisfy a mandate such as a Renewable Portfolio. This subject is covered further in The Interaction of Green Tariff Programs: Avoiding Double Counting, Improving Results (page 57).

Green pricing tariffs should be cost reflective.
The green pricing product price should incorporate the incremental cost of the renewable energy supply and perhaps the marketing and infrastructure expenses of selling a differentiated green power product. Allow utilities to offer bulk-purchase rates for larger non-residential customers.

Avoid cross subsidies from non-participating customers.
Costs of the renewable electricity should not be allocated to customers who do not participate in the program.

Allow the green power marketing budget to come from the general marketing budget.
Some green pricing programs have stand-alone marketing budgets with costs covered by program participants. Other utilities use general marketing funds to educate consumers about their options. Either approach is acceptable. The use of the general marketing budget is justified to the extent that broader public goals are being supported through public information about renewable energy.

Allow utilities some flexibility in spending for program implementation.
Green pricing program design and marketing have evolved over the past decade. Although regulators may require a baseline of green pricing program marketing activity, they may also allow flexibility and innovation in marketing and certification to increase the potential for market success.

Consider set-asides for specific renewable technologies or environmental programs.
Some green pricing programs allocate a portion of the customers' payments into a fund for specific activities. For example, Santee Cooper has a solar development set-aside, and Portland General Electric offers a "salmon friendly" option with a set-aside for habitat restoration projects. Set-asides allow programs to be tailored to specific local interests. For example, Tennessee Valley Authority's program has a solar set-aside that has been used to install PV in cities throughout their multi-state service territory, thereby increasing the local presence of their program.

Allow the use of Renewable Energy Certificates for supply.
The utility may wish to either acquire the energy demanded by customers, in whole or in part, through procuring or generating the renewable energy directly, or through the purchase of Renewable Energy Certificates. There are pros and cons to each approach, but the utility should be allowed to use RECs for supply so long as the RECs are from projects that meet the

program's criteria and there is adequate geographic disclosure regarding the source of RECs. The ability to use RECs provides greater flexibility when securing supply.[12]

Successful Programs

The National Renewable Energy Laboratory (NREL) releases an annual "Top Ten" ranking of green pricing programs.[13] These programs are ranked based on these criteria:

- green power program renewable energy sales
- total number of customer participants
- customer participation rate
- price premium charged for new, customer-driven renewable power

These are valid metrics of success for any utility green power program, and NREL's list provides a good benchmark for regulators.

Conclusion

Green pricing programs have grown considerably in recent years, both in terms of the number of options available and their popularity with customers. But green pricing program results have also shown that the design of the product has a huge influence on the success of the program. Regulators can guide utilities toward successful programs that meet both public and customer needs with fair and equitable tariffs.

[12] However, either bundled renewable energy or REC contracts for differences are required for price stability products.
[13] http://www.eere.energy.gov/greenpower/markets/pricing.shtml?page=3

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B. Check-Off Programs

Background

In a green power check-off program, a customer makes a voluntary purchase of Renewable Energy Certificates (RECs) from a third-party supplier as an add-on subscription to existing electricity service. This is different from green pricing programs in that the customer makes the purchase of RECs from a utility-approved third party supplier, rather than from the utility itself. The customer's electricity needs continue to be met by his/her traditional supplier.

RECs are supplied by one or more qualified vendors. The purchased RECs can match a percentage of the customer's monthly electricity use or can be a fixed monthly amount.

This type of program is now being offered through several utilities, including Niagara Mohawk (NiMo), Massachusetts Electric, PacifiCorp, and Portland General Electric, and throughout New Jersey.

Because a check-off program is not a renewable electricity service *per se*, there is no regulatory tariff. Check-off program rates are typically determined through a competitive solicitation. However, there are issues that regulators should consider when approving and evaluating check-off programs. Two key issues are: the selection of suppliers for the program; and cost recovery for utility efforts to administer and promote the program. These issues are addressed below.

Program Details

Green power choice programs vary widely in the number of participating REC suppliers and how supplier participation is determined. There are three general models to consider.

- **Single Supplier**: One REC supplier is chosen through a competitive bidding process to partner exclusively with the utility. The supplier may offer one or more product options.
- **Unlimited, Multiple Suppliers**: Open enrollment allows all interested REC suppliers that meet basic supplier criteria of state licensing and minimum product quality standards to participate by offering one or more products.
- **Limited Multiple Suppliers**: A pre-determined number of REC suppliers (typically 2 or 3) are chosen based on a competitive bidding process. Suppliers may offer one or more product options.

An exclusive utility-supplier partnership (the single supplier model) can have low customer acquisition costs and easy administration by the utility. Measured by the number of customers enrolled and total renewable energy sold, single supplier-utility partnerships have out-performed multiple-supplier utility partnerships consistently. Several single supplier-utility partnerships have been ranked by the U.S. government's National Renewable Energy

Laboratory (NREL) as among the top ten most successful utility green power programs.[14] The primary reasons for the success of single supplier utility partnerships are:

- program simplicity,
- competitively priced, high quality products and services,
- a minimum marketing requirement on the part of the supplier,
- ease of implementation for the utility (record- keeping, billing and customer service),
- close and transparent cooperation between REC vendor and the utility on marketing, public relations, messaging, and customer service, and
- simplified branding.

The Unlimited Multiple Supplier model, used by NiMo and Mass Electric GreenUp Programs, maximizes supplier and product choice for the consumer and is a way to educate customers on the concept and benefits of choice and competition in energy services.

However, multiple suppliers and product choices can pose accounting, billing and information technology complexities that raise management challenges and costs for utilities. Multiple suppliers with multiple offers may also add to customer confusion. Furthermore, open enrollment may not require suppliers to invest in the marketplace, but may instead allow suppliers to rely on the utility for marketing services such as bill inserts, website listings and customer education materials. The initial green choice marketplace may be too small to split among multiple participants in a financially viable way. Preliminary results show low participation rates for the multi-supplier programs.

The Limited Multiple Supplier model seems to offer most of the virtues of the Single Supplier and Unlimited, Multiple Supplier models with few disadvantages. Limiting participation to up to three vendors based on qualifying criteria and a competitive bidding process can reduce complexity for consumers and utilities while fostering a competitive environment for suppliers.

Connecticut has a limited multiple supplier program called Alternative Transitional Standard Offer (ATSO). The Department of Public Utility Control directs the distribution companies to conduct a joint competitive bidding process that allows two winning bidders to offer the same green power service options to all customers across the state.[15] Each may offer a 50% and 100% renewable option. The justification is that offering the same services to all customers across the state will reduce marketing costs. The reasons for limiting the program to two winning bidders and a total of four products include:

[14] National Renewable Energy Laboratory's Top Ten Utility Green Power Programs (as of December 2005) http://www.eere.energy.gov/greenpower/markets/pricing.shtml?page=3
Single supplier utility partnerships in the Top 10 ranking include Portland General Electric, City of Palo Alto, and Silicon Valley Power.

[15] Connecticut Department of Public Utility Control Docket No. 05-03-14
http://www.dpuc.state.ct.us/FINALDEC.NSF/0d1e102026cb64d98525644800691cfe/50ebfba146b6df5985257068005c33d3?OpenDocument&Highlight=0,05-03-14

- encourage greater investment by competing bidders in marketing resources through competition,
- avoid potential customer confusion from an excessive number of products,
- efficient use of utility resources to facilitate the program, and
- avoid the potential "free-rider" problem of companies relying primarily on utility bill inserts, web listings, and other free marketing resources to sell their products.

This hybrid approach seeks to balance the benefits of a competitive bidding process and maximizing customer participation, with the goal of encouraging consumer choice.

Supplier Qualifications

Regulators should consider limiting supplier participation to up to three suppliers based on qualifying criteria and a competitive bidding process. This limitation can help to reduce complexity for the consumer and utility while fostering a competitive environment for suppliers.

A competitive bidding process should be based on commonly-accepted utility procurement principles and practices, including:

- clear descriptions of products and services sought,
- clear qualifications for suppliers,
- clear criteria for bid evaluation,
- good documentation of process and decisions, and
- balancing of the public's right to know with vendors' legitimate needs to protect commercial information.

Suppliers should**:**

- be licensed to do business and demonstrate creditworthiness (but do not need to be licensed as electricity suppliers);
- be able to show they can deliver the proposed products;
- comply with Electronic Data Interchange (EDI) standards in order to facilitate billing with the electric utility;
- be experienced in renewable energy and retail marketing;
- demonstrate that their product offerings are consistent with product standards set forth by the law or regulatory agency;[16] and
- present a marketing plan to ensure continuing access to bill inserts, ballots, and integrated customer communications.

[16] Some agencies have used the Green-e renewable energy certification standards as a benchmark: http://www.green-e.org/ipp/standard.html

Product Qualifications

Products can be judged based upon:

- type of renewable resources
- percentage of new renewable resources in the product content,
- price, and
- inclusion of in-state renewables.

Requests for Proposals

Regulators and utilities have several approaches to consider for issuing a Request for Proposals (RFP):

- **Joint Utility RFP:** All interested utilities issue a single RFP. The selected supplier(s) will serve all participating utilities. The participating utilities review the responses. Statewide consistency could be a plus.

- **Single Utility RFP:** Each participating utility issues its own RFP for supplier(s) to serve its customers. This could be more efficient for each utility.

- **Third Party Evaluation:** (for either of the above options). A neutral third party issues the RPF and evaluates responses. This approach could be perceived by customers and regulators as fair and unbiased.

Statewide distribution utilities could conduct a joint selection and bidding process that offers the same green power services to all customers across the state. Offering the same products statewide will reduce marketing costs and enhance ease of marketability statewide by state, public, utility, and supplier public awareness efforts. The contracts between the distribution companies and REC suppliers may need to reflect differences in billing procedures, information technology, internal company procedures, and commodity electricity prices. However, the differences should be minimized to the extent possible to allow essentially the same green power services to be offered to customers across the state. Suppliers should provide a justification for price differentials for the same product offered in multiple service territories.

Model Request for Proposals (RFPs) exist in the public domain (see link to these documents in the "Information Resources" section of this report).

Winning bidders should commit to delivering their promised product content at the promised price for the duration of the contract term. Suppliers should adhere to their proposed marketing plans. This will ensure a level playing field and prevent suppliers from over-stating the advantages of their product in order to win the bid and then shortly thereafter modifying their pricing and content. A minimum three-year term is recommended to leverage maximum investment by suppliers in the success of the program. Interview participants indicated that supplier contracts must be for three to five years at the very least in order to make the program financially viable.

Some competitive suppliers are non-profit organizations. If a utility uses a 501(c)(3) non-profit organization to provide green products, customers may be able to claim tax deductions for the check-off contributions.

Individual vendors may not have the resources to conduct sufficient outreach to a utility's customers. Therefore, utilities, vendors, and regulators may need to cooperate to educate the public about this choice.

An active utility role in the enrollment process can be key to customer participation and program success. Utilities can:

- help train the call center on the program basics,
- cooperate on joint press releases, and
- participate in press events with suppliers.

Program Cost Recovery

Utilities will incur costs in implementing check-off programs. These expenses, if prudently incurred, may be recovered:

- from program vendors (paid for by their customers),
- in general rates, if seen as benefiting society as a whole, and/or
- from public benefit funds.

Regulators should require periodic reporting of program performance by utilities and suppliers to ensure that cost recovery is warranted. Utilities could be given incentives to enhance the success of check-off programs.

Summary of Best Practices for Green Check-Off Programs

- Limit the number of participating suppliers to three, at most in order to have a successful, easy to administer program.
- Select the supplier(s) through a competitive process in order to obtain the least cost resources.
- In order to ensure that the programs result in additional renewables that would not otherwise have been constructed, suppliers should provide products that are based on new renewable resources, preferably covering a substantial portion of a customer's electricity usage.
- Provide a mechanism for utilities to recover costs for their administrative and marketing support of the program. If utility costs are not covered, they will not be motivated to promote the program or even get it off the ground.
- Compare the program to those listed in NREL's annual Top Ten rankings. See page 13 (Section A above, subsection on Successful Programs) for more detail.

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C. Community Aggregation

New community aggregation programs are developing as a mechanism for communities to bring more renewables into the supply mix than are being provided by the host investor owned utility and they are willing to pay the costs through a community participant fee. Since community aggregation programs must be approved by state regulatory commissions (this is not municipalization but the separation of the electricity supply and supply payment) and involves a novel way of increasing renewable supply for a particular geographic area rather than for individual customers, the authors thought it appropriate to add it to this Handbook. It can offer a creative, effective, and economic way of bringing renewable energy and energy efficiency services to communities when the circumstances are right, and we expect that community aggregation issues will crop up more frequently in legislative and regulatory activities in coming years. In addition, community purchasing of renewable energy has begun to take shape through the Union of Concerned Scientists and the U.S. Department of Energy's Energy Freedom Challenge, with the ultimate goal of motivating U.S. cities to move toward getting their yearly power to 50 percent green energy. These efforts could evolve into community aggregation type programs. Though community aggregation is unlikely to enjoy wide spread implementation due to the complexity of designing an effective program, when all the critical pieces are present, community aggregation can be a powerful and beneficial tool for bringing environmental benefits to retail customers.

Background

Community aggregation is when local governments aggregate the loads of electric service customers within its jurisdictional boundaries and facilitates the purchase and sale of electricity and other energy services; it is an alternative to the electricity service provided by their retail utility (or standard offer service).[17] Strictly speaking, community aggregation is not a regulated supply service. Rather, it is an alternative to it. It is include here because regulators are often interested in alternative ways of meeting the needs of customers, the communities they live in, and the environments that affect them. Community aggregation permits cities and counties to purchase and sell electricity on behalf of utility customers in their jurisdictions while remaining within the host utility's service territory. The participating communities must pay the host utility for billing, transmission/distribution and any other utility services they use. As with other green programs described here, the regulatory commission has the responsibility to ensure that there are no cross subsidies between participating and non-participating customers and that fees are cost reflective and fair.

A local government community aggregator does not become a municipal utility and does not own or operate the transmission and distribution systems. Rather, it procures electric power from the wholesale markets; that power is delivered to the end use customers by the local investor owned utility (IOU) across its transmission and distribution facilities.

[17] Community aggregation is sometimes referred to as Muni-lite, Opt-out Programs, or Community Choice Aggregation – CCA.

A community aggregator is similar to an electric service provider (ESP) that sells electricity to direct access customers; but with two differences: (1) community aggregation programs usually operate under different sets of rules established by the state utility commission than do ESPs; and (2) aggregation programs are geographic specific, customers are usually acquired through an 'opt-out' process (i.e. everyone within the jurisdictional boundary of the city or county is in the program unless they indicate they want to opt-out) while ESPs acquire their customers one at a time (opting in).

Given the small number of community aggregation programs that have been implemented, this discussion is primarily anecdotal. However, because several California communities are looking into community aggregation (known there as Community Choice Aggregation) it may pick up momentum in the future as an alternative to full retail choice or municipalization and as a supplement to state RPS programs.

The Motivation for Community Aggregation

In Massachusetts, the first state to pass a community aggregation law, community aggregation was seen primarily as a way to bring price competition to small customers. Barnstable County had a very active county energy committee which spearheaded the passage of the Massachusetts legislation because of concern about restructuring and whether small customers' needs would be served under full retail competition. The Committee was motivated by price, market leveraging (with several communities going together to aggregate load), and the ability to provide renewable energy and energy efficiency services that would exceed those offered under 'basic service.' The one program that has been implemented in Massachusetts, the Cape Light Compact,[18] includes energy efficiency and green pricing programs and met the state RPS mandate before any other energy service provider in the state had done so.

In Ohio, community aggregation was developed primarily as a tool to encourage price competition to standard offer service under Ohio's restructuring legislation. Of the programs that have been implemented in Ohio, only one, the Northeast Ohio Public Energy Council -- NOPEC,[19] provides environmental benefits that could be characterized as a "green tariff." In addition to offering a cleaner supply mix, NOPEC has partnered with their supplier to build a 26 kilowatt solar array and brought schools in Northeast Ohio into the Solar Powered Schools Program. The other programs are aggregating exclusively for price competition.

In California, direct access to competitive markets by retail customers was suspended after the energy crisis of 2000-2001. Some large customers that had already selected alternative suppliers have continued to receive retail service from them, but for most California electricity customers,

[18] The Cape Cod and Martha's Vineyard Cape Light Compact serves 180,000 customers who receive the same electricity mix as does everyone else in that service territory. However, the program offers both an energy efficiency program and a green pricing program. Also it is the only energy service provider to date that is in compliance with the State's RPS mandate.

[19] The largest program in the country as well as the largest in Ohio is the Northeast Ohio Public Energy Council (NOPEC) – 115 communities 450,000 customers. This is also the one program that is providing real environmental benefits, though very little from renewable energy. The program offers 98% natural gas generated electricity and 2% from renewables compared to the regular mix in this area that comes from 87% coal fired and 13% nuclear power. In 2004 NOPEC saved customers more than $13.4 million and prevented 204 million tons of carbon dioxide emissions.

Community Choice Aggregation is the only option for accessing the competitive market and it may be an economical way of shifting to a greener electricity mix. California communities that are looking at community aggregation are driven by a desire for environmental improvements beyond what they would otherwise receive from their retail utility as well as the opportunity to stabilize and lower electric rates.[20]

Program Details

Exit Fees: Neither Ohio nor Massachusetts requires exit fees for communities leaving the standard offer system. In Ohio, customers can reconsider their original decision and opt out after two years (and every two years after that). If they leave in between those times, they must pay the aggregation service provider a small fee. No fees are charged by the aggregator in Massachusetts for customers that leave the system. In California, there are hefty exit fees [21] that are required by the California Public Utilities Commission to be paid by customers of community aggregation programs for leaving the IOU system. These can act as a deterrent to many local governments in the early years of the program until the exit fees end.

Billing: Having the distribution utility do the billing is generally considered to be a benefit as long as fees are reasonable.[22] Community aggregation charges that may appear on the utility bills include:

- any non-bypassable charges (exit fees),
- metering and billing,
- operations and scheduling,
- transmission system, and
- commodity costs.

In most cases the community aggregator provides the utility a schedule of its rates. The utility automatically calculates the charges, bills the customer, collects the fees and remits those back to the CCA, minus billing and metering charges, transmission and distribution charges, and any non-bypassable charges that go to the state. The various fees may each be separate line items[23] or rolled into one rate/kWh depending upon the laws/rules of that state.

One distribution utility requires the community aggregator to collect its own meter data and submit them to the distribution utility, which then applies the commodity costs and other fees to

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[20] Though California's electricity mix is quite clean compared to that of other areas of the country, the dependence on natural gas-fired generation can result in significant price volatility. ,In the western US, some types of renewable resources are available at or below the cost of natural gas combined-cycle plants.

[21] These exit fees are due to costs related to the California energy crisis. The fees have different periods of duration: State Bonds to pay for high priced energy during the energy crisis end in 2023; contracts that provided extra energy during the crisis end in 2010; restructuring transition costs (e.g "stranded costs" from nuclear plants) end in 2008; and the costs of managing the PG&E Bankruptcy (for communities in that service territory) end in 2013. The largest drops in exit costs to communities occur in 2008 and 2013.

[22] Both the Cape Light Compact and NOPEC thought the current charges were fair.

[23] California requires each element to be a separate line item on the bill.

be collected through the electricity bill. This requirement is burdensome and discourages community aggregation.

Billing should be sufficiently flexible to allow local governments a range of billing and program options. For instance, the billing should allow for options like different rates for different customer classes and other customer class rate options as well as 'budget billing'.[24] In Ohio, the bill is presented as a flat rate off the shopping credit. Massachusetts has gone from one single flat rate to differential rates depending on whether the customer is residential or commercial. In addition, communities may offer other energy services like energy efficiency, green pricing, and PV leasing or purchasing, for which they would like to bill the customer. Such billing flexibility allows communities to tailor their energy services to meet local needs.

Metrics of Success

Metrics of success for community aggregation programs include:

- The number of customers being served by the program(s),
- The ability to attract a good competitive supply contractor,
- The avoided tons of carbon (and other environmental benefits) due to the activities of the project,
- The financial savings to the customers compared to standard offer service.
- The ability to deliver real environmental benefits significantly beyond what the distribution utility would do (e.g. meeting a 40 percent RPS target rather than the state mandated 20 percent target),and
- Other energy services at the same cost (or slightly less) compared to power and energy services from the distribution utility.

Promoting Community-Based Renewable Energy

In May, 2005, the Minnesota legislature passed Community-Based Energy Development (C-BED) legislation to promote locally owned, renewable energy projects through the use of a new financing tool. Under the statute, utilities are required to offer power purchase agreements that provide developers with front-end, higher rates in exchange for lower rates in the later years, essentially allowing a developer to "borrow" from the later years of the contract to help offset the startup costs for the project. C-BED is intended to allow community-based projects easier access to better financing and empower communities to develop local wind resources which keep the economic benefits of those projects within the community. Although the new statute does not require that utilities purchase power from C-BED projects, it does require that they establish a C-BED tariff. For the utilities that develop or purchase new generation to satisfy the Minnesota Renewable Energy Objective, the statute requires those utilities to take reasonable steps to determine the availability of suitable C-BED projects. The front-end loaded contract is in lieu of other state subsidies.

[24] Budget Billing is when the customer pays a predetermined amount every month. It is attractive for customers on fixed incomes, although it masks the price signals of seasonal variation in usage and rates.

Best Practices

For Regulators: The rules for community aggregators need to be fair and balanced compared to those for standard offer service. Regulators should adopt rules that ensure the following best practices are upheld so community aggregation programs can be successful:

- Cooperation by the IOU is mandatory if the program is to be successful.
- An opt-out process for customer participation is the practical, economically feasible approach.
- The default utility should accurately calculate customer electricity rates and bills.
- Any exit fees should be fairly calculated and not act as an insurmountable barrier to community aggregators.
- The default utility should take responsibility for the accuracy and timeliness of customer load information and lists (including "mover's lists" and "refresh lists"). The rules for updating customer lists should be aggressively enforced.
- If the state has a fund for educating the public about their energy options community aggregation programs should have access to some of those funds for promoting their programs and/or for establishing their programs.
- If default utilities receive state funds for energy efficiency programs or other energy incentive programs, community aggregation programs should receive their pro-rata share of such funds.
- At a minimum, default utilities should offer Rate-Ready Billing (the default utility reads the meters and applies the community's rates to the appropriate bills) with flexibility to add on-bill charges for other energy services offered by the community.
- Community aggregators should be free to adopt rate designs of its own choosing, including any offered by the default utility.
- Commission review and approval processes should be efficient to reduce regulatory compliance costs.[25]
- Once the local government has instituted an aggregation program, regulatory oversight of that program should be kept to a minimum.
- Regulatory uncertainty should be reduced as much as possible. The regulatory rules for community aggregators should be perceived as stable over the long term. Any program rule changes (or other regulatory changes that will directly affect community aggregation programs) should be reviewed in light of existing programs to ensure they do not cause economic damage to the communities or the program participants.
- At the outset, rules should be clear about what happens if a community aggregation program ends and the customers want to return to the default utility.

[25] Regulators interviewed for this paper felt there was little if any need for Commission pricing oversight since community elected officials will be accountable to voters if the aggregation program's rates are not reasonable.

- Regulatory commissions can encourage community aggregation by helping communities understand some of the technical and regulatory issues they must confront.

For Communities: Designing and implementing a community aggregation program is a very complex undertaking both from a process and a technical perspective. An advantage communities have is that they tend to be good at educating their citizens on a variety of topics. A successful community aggregation program requires much public education. Listed below are some best practices for communities considering community aggregation.

- Be clear about goals and objectives and how conflicting ones will be reconciled. Understand tradeoffs and have full discussions of these tradeoffs at the political level. Indicate priorities among conflicting goals.
- Prepare a detailed aggregation plan and involve community leaders and elected officials.
- Have an active local official to 'champion' the program educate other relevant public officials.
- The program should educate its citizens regarding the program's advantages, disadvantages and values as well as a citizen's ability (and rules) for opting-out of the program.
- The program should educate regulators concerning the program's goals and objectives so regulatory rules and requirements will be compatible with community needs.
- Ancillary energy services and programs (e.g. energy efficiency and green pricing) should be incorporated into the program to the extent possible because they contribute to the overall satisfaction of the participants and the ultimate success of the program.
- Use professional technical assistance to help in the initial design of the program, design of request for proposals, and review of legal documents. Grants may be available through clean energy funds, state energy offices or other sources.
- Incorporate renewable energy to the maximum extent possible and feasible within the economic constraints of the program. Renewables can help stabilize electricity rates over the long term as well as reduce negative environmental impacts from community electricity use. This could also result in long term cost savings for community aggregation participants as environmental regulation becomes more stringent over time.
- Investigate different resource mixes and a range of purchasing options for obtaining your supply resources (e.g. natural gas and renewable energy resources either from one competitive supply contractor or through a mixture of contract purchases, spot market purchases, self-financing of projects with tax exempt bonds, REC purchases, and off-system sales).[26]

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[26] This is the place where outside technical assistance is particularly helpful.

Conclusion

Community aggregation programs have the potential to offer both economic and environmental benefits tailored to local community needs. Increased numbers of community aggregation programs in the future will provide useful on-the-ground experience and new information, and expand knowledge of best practices.

Incorporating Certification and Verification Costs into Voluntary Market Programs

Some green pricing programs, check-off programs, and community choice aggregators may seek certification for their retail renewable energy products. There are several organizations providing certification programs, the Green-e program (www.green-e.org) being the industry leader. Certification instills consumer confidence, helps shape markets, and legitimizes intangibly-differentiated products. Certification also ensures that best practices are being met, assures marketers, regulators, and customers that products are of the highest quality, and may save state resources by reducing regulatory oversight. Certification is voluntary, and products must meet standards in order to be certified and undergo annual audits to keep it.

Because certification incurs costs, including an annual certification fee, the participating utility and/or green power marketer must include those costs in tariffs and prices. In addition, some certification programs require that renewable energy be from "new" facilities and exclude some energy sources that are in the debatable area of what is considered renewable (for example, only hydropower certified by Low Impact Hydropower Institute is eligible). This means that only "premium" renewables qualify, which may have an impact on price. Therefore, when setting tariffs, regulators may need to consider how those costs should be treated.

III. MANDATORY MECHANISMS

A. Renewable Portfolio Standard (RPS) Laws

Background

Renewable Portfolio Standard-type policies are aimed at increasing the contribution of renewable energy in the electricity supply mix. The RPS is generally intended to create a stable and predictable market for renewable electricity that maximizes the benefits of renewable generation while minimizing costs.

Recently emerging as one of the leading policies to support renewable energy generation, RPS policies have been adopted in 21 states, the District of Columbia, Australia, Belgium, Italy, Sweden, and the United Kingdom. Legislation for a national RPS has been considered by the U.S. Congress and is currently being considered in several other countries around the world. The Union of Concerned Scientists projects that RPS programs in the U.S. could result in more than 25,000 MW of new renewable capacity by 2017.[27]

The "No Tariff" Approach to Renewable Energy

Regulators may want to encourage utilities to incorporate renewable energy into their regular utility tariffs, whether through a Renewable Portfolio Standard or some other means. A recent study by Lawrence Berkeley National Laboratory (LBNL) showed that utility resource planning is becoming an important driver of new renewable generation in the West, proposing more than 8,000 MW of new renewable generating capacity by 2014.

Nearly half of these additions are planned not because of state or federal requirements, but because utilities are finding that renewable energy can make good business sense for them and their customers. The increase in utility acquisition of renewable energy is motivated by the improved economics of renewables as well as an increasing volatility of natural gas prices and environmental compliance risk in fossil-based generation portfolios.

[27] "Renewable Electricity Standards at Work in the States" by Union of Concerned Scientists: http://www.ucsusa.org/clean_energy/renewable_energy/page.cfm?pageID=47

Program Details

General: Renewable Portfolio Standards typically require that a certain percentage of a utility's overall or new generating capacity or energy sales must be derived from renewable resources. RPS features vary from state to state with respect to:

- target level,
- whether the target is based on a percent of energy sold or installed capacity,
- when targets must be met,
- resource eligibility,
- scope of geographic eligibility,
- preferential policies to encourage particular types of renewable energy, such as specific resource targets or multipliers,
- limits on costs or cost recovery,
- penalties for non-compliance, and
- whether RECS can be used, and/or whether power must be purchased.

Some state RPS policies are technology/fuel neutral and some mandate that a share of the obligation be met by specific technologies, such as solar photovoltaic.

Percentage obligations range from two percent in Iowa to 30 percent in Maine.[28] The great differences in target percentages are due in part to the varying amount of renewable energy already on the system at the time the law is passed. Iowa had to build more renewable energy capacity following the passage of its law than did Maine.

Cost Recovery and Cost Containment: The cost implications of an RPS depend on the compliance methods used by the obligated entities as well as the implementation details. In RPS programs where long-term contracts are available, renewable energy can be procured competitively and often at reasonable prices.[29] Without long term contracts, the ability to finance new renewable projects will be limited and compliance costs will probably increase.[30] An RPS based solely on short-term contracts can increase costs and decrease the diversity of renewable technologies that are developed, although diversity can be encouraged through the use of resource tiers or credit multipliers.

[28] When Maine enacted its RPS in 1999, its electricity mix was approximately 35 percent renewables, so its RPS actually allows for a reduction in the amount of renewables in the state.
[29] Ibid. This is supported by data from Texas, Minnesota, California, Iowa and Wisconsin. "Balancing Cost and Risk: The Treatment of Renewable Energy in Western Utility Resource Plans" by Bolinger and Wiser reaches a similar conclusion. http://eetd.lbl.gov/ea/ems/reports/58450.pdf
[30] Ibid. This has been the case in Massachusetts and Connecticut and may spread to other jurisdictions as compliance pressures increase.

Compliance: Measuring the success of an RPS relies heavily on the method used to track compliance. There are two main ways of verifying and tracking compliance with the RPS: (1) contract path, and (2) the use of renewable energy certificates (RECs). RECs are financial and accounting tools that offer increased flexibility and electronic data assurance, and are quickly becoming the most widely used verification method for the RPS as well as other renewable energy policies and voluntary programs.

REC Tracking 101

Renewable energy generation can be accounted for in two different ways: through contract-path auditing and through tracking systems. Tracking systems are becoming the preferable method because they support policy compliance and enhance markets.

Tracking systems are databases, typically electronic, with basic information about each MWh of renewable power generated in the region. Electronic tracking systems allow Renewable Energy Certificates (RECs) to be transferred among account holders much as in online banking.

Renewable energy tracking systems assign a unique identification number for each megawatt hour of renewable electricity generated in that region. The database has several fields for each megawatt hour, such as facility location, generation technology, facility owner, fuel type, nameplate capacity, the year the facility began operating, and the month/year the MWh was generated.

A tracking system can be used by regulators as a registry of generating facilities, as a means of verifying compliance with a Renewable Portfolio Standard, for aiding in the creation of disclosure labels, and for other policy purposes such as verifying wholesale supply for green pricing programs.

There are several regional tracking systems in operation in the U.S., and more under development. Fully operational tracking systems include the New England Generation Information System, ERCOT's Texas Renewables, and PJM's Generation Attribute Tracking System . Tracking systems under development include WECC's Western Renewable Generation Information Tracking System and the Midwest Renewable Energy Tracking System.

In order to facilitate transactions among the various regional tracking systems, the Center for Resource Solutions is facilitating the formation of a new organization known as the North American Association of Issuing Bodies (NAAIB). The NAAIB is a voluntary association of certificate tracking systems, regulators and interested market participants who want to prevent double-counting and to promote harmony among certificate tracking systems in North America. Such harmony will encourage trade, create a common currency for renewables, prevent double counting, and support existing and emerging markets for renewables. Parties involved in the development of the NAAIB include tracking system operators, energy regulators, generators, developers, renewable certificate marketers, and environmental organizations in Canada, the U.S. and Mexico. For more information: visit:www.resource-solutions.org/policy/naaib/ .

Cost Recovery and Containment Methodologies: The table on the following pages indicates the methods of cost recovery and cost containment used in different RPS programs.

Table 2. State RPS Program Cost Recovery Summary

State	Standard	Recovery of Costs	Cost Cap	Penalties
AZ	15% by 2025	Use PBF funds	$1.05/mo res. $39/mo non-residential $117/mo loads >3M	Currently no set penalty. Commission has power to fine utilities if needed.
CA	20% by 2017* (20% by 2010 33% by 2020)	PBFs may be used for costs over the market reference price (they have not yet been required in CA)	Amount of PBF funds available	
CO	10% by 2015	Costs are not to exceed $0.50/mo/res.cust.	Annual spending limit of 1% of electric utility bills	No penalties yet
CT	10% by 2010	Costs recovered in rates		$0.05/kWh
District of Colombia	11% by 2022	Cost is on the supplier, most always resulting in increased cost to consumer	No cap	$0.025/kWh
HI	20% by 2020	Costs recovered in customers' rates	100% of avoided cost	Currently no penalty
IA	2% by 1999	Costs recovered in rates		
IL	5% by 2010; 15% by 2020	Costs recovered in rates		Goal, no penalty
MA	4% by 2009	Recovered in customers' rates	The Alternate Compliance Mechanism is $50/MWh	
MD	7.5% by 2019	Costs recovered must be at or below penalty levels		$0.02/kWh
ME	30% by 2000	Costs recovered in customers' rates	No max cap	Fines & possible license revocation
MN	19% by 2015	Resource Plan must be approved then costs passed on to consumers	No cap set in law	
MT	15% by 2015	Contracts must be pre-approved by PSC then costs passed on to consumers.	No cost increases	$10/MWh
NJ	6.5% by 2008	Costs recovered in customers' rates	Max $250/MWh	ACP $50/MWH SACP $300/MWH

Table continues on next page

Table 2. State RPS Program Cost Recovery Summary (continued)

State	Standard	Recovery of Costs	Cost Cap	Penalty
NM	10% by 2011	Can recover everything at or < cap	Sets a PRC cap	
NV	20% by 2015 (5% solar annually)	Investor-owned utilities may collect revenues from electricity customers to pay for renewable energy separate from other wholesale power purchased by the utilities. The Independent TRED Trust receives the proceeds from the TRED Charge and remits payment to renewable energy projects that deliver renewable energy to purchasing electric utilities.		
NY	24% by 2013 (+1% from voluntary mkt.)	Volumetric charge on customers' bills	No cap, but central procurement by NYSERA prevents bids that are too costly	No penalty because of central procurement, not individual suppliers
PA	8% by 2020	Costs recovered in customers' rates. Each utility has to prove legitimacy of claims	200% avg. mkt. Value of REC	To be determined
RI	16% by 2019	Cost recovered in rates	The Alternate Compliance Mechanism is $50/MWh	
TX	20% by 2020	Costs recovered in customers' rates		Automatic $50/MWh
VT	Meet growth or 10% by 2012	Costs recovered in customers' rates		
WI	2.2% by 2011	Cost recovered in rates to consumers. RPS does allow extra cost to be recovered through green pricing program.	No cap	$5000 to $500,000

All of the states but one allow utilities to recover RPS costs through customer rates. Arizona uses public benefit funds to pay for RPS compliance. New York recovers the cost in rates but includes the cost as a separate volumetric charge on the customers' bills. New York also has a central procurement system whereby the New York State Energy Research and Development Authority (NYSERDA) purchases renewables on behalf of customers.

Three states have an alternate compliance mechanism (ACM) which allows the obligated party to pay a per kWh fee into a fund instead of meeting its mandate. The fund can be used for a variety of purposes, usually relating to helping to develop the market for renewables. The ACM ensures that the costs of the RPS never exceed a certain level. The fines and the ACM act as the upper limit on compliance costs, because the non-compliance fee per MWh becomes the highest price that a utility would pay for a MWh of renewable electricity or a REC; above that point it would be cheaper to pay the fine or the ACM than to obtain the renewable energy. Costs caps can be established through the use of a market price referent (MPR), based on market costs of electricity. Periodic review can ensure that it is tracking current market conditions. Some states, e.g., California, allow this method to set a cap and fund the over-MPR costs of new projects with funds from the state's Systems Benefits Charge.

There have been no reported cases of the cost of renewables causing excessive rate increases (though not all states have fully implemented their RPS programs). Where competitive long-term contracts are used to purchase renewables, the costs have been relatively low, sometimes below the cost of conventional power. Nevertheless because of concern about this potential many states have included some cost control mechanism in their statutes or regulations.

Capacity-based vs. Energy-based RPS: There are two main metrics for the RPS based on the output of a facility: (1) energy, measured in megawatt hours (MWh); or (2) capacity the facility has to produce – measured in Megawatts (MW). Either of these metrics can be used to set the quota obligations of the RPS. Of the twenty two U.S. states (including Washington, D.C.) with RPS type policies, nineteen use energy based (MWh) standards while the other three use capacity based (MW) standards.

The energy-based standard is used by the majority of these programs because of the ease of applying it to either generators or retailers and is directly related to load growth. The standard is usually set as a percentage of a utility's retail sales, but can also be applied to the producers as a percentage of electricity generated. Energy-based standards are slightly more complicated to implement as constant tracking of generation must occur and be verified to prove compliance over the year.

A capacity-based standard is simpler to set, because it is an overall increase in renewable generation capacity for the year. Calculations for the *obligated parties* are also a bit more complicated because the amount of capacity required under an RPS does not easily translate into obligations for individual companies and must be based on market share calculations using the previous year's sales (not capacity). Finally, another shortcoming of the capacity standard is that it does not provide an incentive for efficient system performance. With a capacity-based standard, there is little incentive to optimize investments in Operations and Maintenance, to consider whether transmission congestion will curtail output, or to even operate the facility.

Multi-Tiered RPS and Credit Multipliers: Because a simple RPS program will tend to favor the least cost renewable resources, some RPS rules create technology tiers or credit multipliers to foster technology diversification or the development of one or more specific renewable energy technologies. Multiple technology tiers allow regulators to differentially encourage specific technologies that may be better matched to the available resources in a given region. Each tier has its own targets. For example, Maryland's Tier 1 sources include solar, wind, qualifying biomass, methane from the anaerobic decomposition of organic materials in a landfill or wastewater treatment plant, geothermal, ocean, fuel cells powered by methane or biomass, and small hydroelectric plants. Tier 2 sources include hydroelectric and waste-to-energy and poultry litter incineration.

Credit multipliers offer specific renewable technologies multiple "credits" for each megawatt-hour of production. In New Mexico each MWh of solar power is worth three MWhs toward the RPS target.

Either of these approaches can give flexibility to the policy, allowing it to be better adapted to changing environmental and market conditions.

Deliverability Requirements -- Local versus Regional Resources: The intent of many RPS-type policies is to increase the proportion of renewable generation to improve environmental and economic conditions in the state where the policy is being implemented. Therefore, many policies include requirements for generation facilities to be located locally. Regardless of whether RECs are eligible for RPS, RECs tracking systems can be used to verify the location of generation and ensure compliance with geographic criteria.

It is not certain how geographic restrictions affect costs, but looser geographic restrictions probably result in lower costs, because that particular approach opens doors to more competition and possibly geographic areas rich in renewable resources. But environmental quality is generally a regional issue -- pollution is not limited to politically designated state or national boundaries. This is particularly true for "greenhouse gas" emissions.

Regulators may want to allow RECs to be used for compliance, but limit the geographic sourcing boundaries of those RECs. Some states, such as California, have also included deliverability requirements mandating that any out-of-state facilities used to meet the RPS requirements verify that the power and RECs were delivered into California. In sum, the local versus regional resource decision may be a tradeoff between greater local economic and environmental benefits versus lower costs.

Renewable Energy Certificates and Other Flexibility Mechanisms: Flexibility is important when designing an RPS because there may be unforeseen conditions that result in supply constraints or unexpected market demand that make RPS obligations unrealistic. Flexibility can allow for the most efficient means of meeting compliance with the standard. Obligated entities may be allowed to meet their RPS requirements with generation from facilities that they own or construct, through bilateral purchases of renewable electricity from independent generators, or with RECs.

A REC, created when a megawatt-hour of renewable energy is generated, is a purely financial product which can be traded separately from the underlying electricity generated. REC transactions allow obligated parties to comply with the RPS by purchasing RECs in lieu of directly purchasing renewable electricity or building and owning facilities. However, for RPS programs to capture the price stability benefits of renewables, out of state RECs must be bundled with energy or purchased through a contract for differences.

Relative to verifying actual renewable electricity contracts to track compliance, the use of RECs and a properly designed tracking system can create liquidity in the marketplace, increase compliance flexibility, and ease administrative burdens by simplifying compliance. If compliance policies are overly flexible and/or lack verification protocols, the likelihood of non-compliance or even gaming can increase. Therefore, the administering agency needs the power to make decisions based on current and expected market conditions while maintaining consistency with the state's RPS goals.

Best Practices

The purchase obligations should drive development of new renewable generation.
In most cases, the intent of RPS legislation is to increase new renewable energy development. A primary objective of the RPS should be the creation of a stable and predictable marketplace that will support this growth. This can be accomplished by specifying as part of the eligibility requirements that facilities must have become operational after a certain date. Existing renewables can be included as a "baseline" that is built upon through new renewable purchases. Including existing renewable energy facilities in the baseline of an RPS provides financial support for those facilities, helping to extend their operational life. But an RPS that can be satisfied using exclusively existing sources of renewables, such as the RPS in Maine, will not result in any of the goals typically articulated in an RPS law (such as diversifying the energy portfolio, improving the environment, stabilizing fuels costs, meeting load growth, etc.).

Resource eligibility decisions should be made with care and consistent with goals.
The development of a precise and comprehensive definition of eligible renewables should be based on careful examination of the resources that are regionally available, the goals of the program and resource costs. It is also important that supply and demand be balanced with available resources and that those resources can be developed at a reasonable cost. In general, unless specified, the least-cost renewables will be used to meet the mandate. If development of a specific type of resource is desired, such resources can be differentially encouraged through the use of multiple "resource tiers" or "credit multipliers" (see below).

Purchase obligations should be durable and increase gradually with time.
Increasing the purchase obligation overtime will encourage continued investment in new renewable generation and result in a stable, predictable market. For example, an RPS that has a goal of 20% by the year 2015 can have interim targets for minimal annual increases to encourage

smooth growth and to avoid 'boom and bust' periods. Alternatively, a capacity based standard might require 1000 MW of new capacity by 2010 with a minimum of 200 MW to be added each year. Overbuilding in one year could be credited toward the following year to encourage economies of scale. This type of ramping-up requirement encourages the construction of new generation as soon as the standard is put into place while supporting a gradual and continued growth over time. Allowing adequate time for final obligations to be met creates a stable marketplace for developers that also encourages the use of long-term contracts. Because of the substantial capital costs involved in financing renewable projects, long term power purchase agreements are essential for cost effectively developing and building renewable generation capacity.

Purchase obligations should be placed equally on all retail electricity sellers, generators, or developers.
Obligations under an RPS generally fall on retailers, but sometimes on generators or developers. Fairness and consistency are essential to ensure that all those who benefit from the increases in renewable supply share in the costs and customers cannot avoid those costs by changing suppliers, as well as costs helping establish a more predictable and stable market for development of new generation. Connecticut originally exempted utilities from the RPS, but competitive electricity suppliers were subject to the requirement, making it difficult for suppliers to compete on rates with incumbent utilities. Equality in costs helps establish a more predictable and stable market for development of new generation.

Programs must have strong and effective enforcement.
Legislation should clearly state what the enforcement policy is and authorize an impartial agency to enforce it. Enforcement is generally the responsibility of the Public Utilities Commission that regulates retail electricity in the state. If there is no signal that non-compliance will result in strong enforcement, RPS targets are likely to be ignored.

Penalties for non-compliance should be higher than the cost of compliance.
Penalties should be effective in creating an environment in which compliance is the best and least cost option. Financially, compliance with the RPS should be the best outcome for the jurisdictional company. Therefore, non-compliance should result in a financial penalty higher than the cost of complying with the standard. Because the cost of compliance is based on the MW or MWh obligation, using the amount of the shortfall to calculate penalties is a simple way to encourage full compliance.

For example, using RECs for compliance can cost a company as little as $2/MWh, while the penalty could be set at $25/MWh, which would effectively set a REC ceiling price of $25/MWh. In some cases, renewable energy from specific technologies can cost more. Setting a specific penalty above the costs of these resources is important if the goal of the RPS is to encourage those technologies. Some states have a specific solar PV requirement in the RPS; solar PV RECs tend to fetch a high price because their cost is high and supply is scarce. For example, in New Jersey the Solar Alternative Compliance Payment was set at $300/MWh, leading to solar REC prices around $200/MWh. This may seem unreasonable, but it is essential that it is financially superior to comply with the standard. In cases with specific resource requirements, penalties should also be specific to these requirements.

Monitoring "new" requirements for compliance.
In terms of monitoring compliance with a "new" renewable requirement, for a capacity based standard, this is a very simple process because the mandate is generally for new generation capacity built during a specified compliance period. For a percentage-based standard, generation information systems and RECs can be used to track compliance, allowing regulators to clearly know not only where and when the electricity was produced, but also to match production with specific information about the facility such as the on-line date, re-power date, receipt of tax incentives, etc. The tracking system employed for tracking compliance must be designed in a way that allows for the tracking of this type of "static" information. Please see the section above on flexibility mechanisms for a more thorough discussion on the use of RECs to track compliance with the RPS.

Conclusion

RPS policies have increased in popularity in recent years, with the number of states in the U.S. passing some form of performance standard growing to twenty one (plus the District of Columbia). Eight of these states enacted an RPS as part of legislation that deregulated electricity generation, although a competitive electricity market is not necessary for an RPS. Several states, including Minnesota, Nevada, New Mexico, New Jersey, Pennsylvania and Texas, have revisited and significantly increased or accelerated their standards. Texas has had so much success that the new renewable capacity coming on-line has outpaced transmission capacity.

Timing regarding policy options can be extremely important. A very positive investment and political environment for renewables can result from commercialization of technologies being at a point at which they are close to being cost-competitive with conventional technologies, coupled with a secure and locally available fuel sources. Potentially large investments and the influx of capital must be considered in conjunction with the need to maintain a diversity of generation technologies, long term stability of the marketplace, past and present energy policies, transmission constraints and the overall financial climate.

Policies must be crafted so that they can adapt to changing market conditions. This has been demonstrated in Texas where the combination of an RPS policy, open access to transmission, favorable market conditions and financial incentives resulted in rapid development of wind generation facilities.

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B. Public Benefits Funds

Overview

A public benefits fund (PBF, or "fund") is a revenue stream most commonly financed through an ongoing surcharge on consumer electric bills (e.g., a "green tariff"), but also occasionally established through lump-sum cash transfers required by state legislation or regulatory settlements. It is used to directly support projects and activities in the electricity sector that provide important public benefits or overcome market barriers. Roughly half the states have established PBFs to promote investments in energy efficiency and/or renewable energy technologies. This chapter focuses on the experiences and lessons from those fourteen states that have implemented one or more PBFs targeting renewable energy (listed in Table 3).[31]

States have typically created renewable PBFs with a common goal in mind: to help protect, preserve, and grow nascent renewable energy markets that might be in jeopardy as the electricity industry was restructured. Accordingly, many of these funds were established in states as they opened their electricity markets to retail competition. In other cases, state regulators have authorized the creation of renewable PBFs (e.g., New York, Pennsylvania), or, alternatively, PBFs arose from utility merger or environmental settlements (e.g., Illinois Clean Energy Community Foundation, Xcel Energy's Renewable Development Fund in Minnesota).

Program Details

PBFs have advantages over other renewable energy policies:

(1) PBFs can be implemented in both restructured and traditionally regulated electricity markets;
(2) PBFs can be financed through several potential sources, in an equitable manner;
(3) The cost of a PBF is fixed and known in advance;
(4) PBFs can be established on an intra-state, state, regional, or national scale,
(5) PBFs maintain significant programmatic flexibility in how funds are used to support renewables, and
(6) PBFs address issues in the same (electricity) sector.

[31] Another common purpose of PBFs is low income bill assistance.

PBFs also have certain disadvantages relative to other policy approaches:

(1) Policymakers (and the public) may perceive that a PBF as a new "tax" on consumption;
(2) The administration and oversight of a PBF can sometimes prove challenging; and
(3) Once collected, PBFs can be and often are susceptible to political attack or expropriation of funds for other government purposes.[32]

Table 3. An Overview of Renewable PBFs in the United States

State	Program Name	Approximate Funding		Administration
		(million $/yr)	(% of revenue)	
CA	CEC Renewable Energy Program	135	0.8%	state agency
	CPUC Self-Generation Incentive Program	100	N/A	state & city agency / utilities
CT	Clean Energy Fund	25	0.75%	quasi-public
DE	Green Energy Program	<1	0.05%	state agency
IL	Renewable Energy Resources Program	5	0.05%	state agency
	Clean Energy Community Foundation	2	N/A	non-profit
MA	Renewable Energy Trust	20	0.7%	quasi-public
MN	Xcel Renewable Development Fund	16	0.4%	utility
MT	Universal System Benefits Program	1	0.3%	utility
NJ	Clean Energy Program	35	0.45%	state agency
NY	NYSERDA Energy Smart	14	0.13%	quasi-public
	LIPA Clean Energy Initiative	37	1.5%	utility
OH	Energy Loan Fund	<15	<0.15%	state agency
OR	Energy Trust of Oregon	10	0.6%	non-profit
PA	Sustainable Development Fund	5	0.1%	non-profit
	Sustainable Energy Fund of Central Eastern PA	3	0.1%	non-profit
	Met-Ed Sustainable Energy Fund	1	0.1%	non-profit
	Penelec Sustainable Energy Fund	1	0.1%	non-profit
	West Penn Power Sustainable Energy Fund	2	0.1%	non-profit
RI	Renewable Energy Fund	3	0.5%	state agency
WI	Focus On Energy	3	0.1%	state agency

Level of Funding: Ideally the amount of funds collected for a renewable PBF should be based on the public benefits derived from use of the funds. Rarely, however, are funding levels set in such an optimal fashion. Instead, the size of the public benefits charge on electric bills is based on a political decision and is lower than would be warranted by a cost-benefit analysis of the fund's activities. Table 3 shows that funding levels for renewable PBFs in the US range from less than 0.1 percent to 1.5 percent of retail sales revenue, with a weighted average of around 0.7 percent of revenue.

[32] At least six state renewable energy funds have recently been the target of legislative or gubernatorial raids aimed at balancing deficit-ridden state budgets. Some of these raids have been successful (e.g., California, Connecticut, Massachusetts, Wisconsin), while others have, at least for the time being, been successfully thwarted (e.g., Illinois Clean Energy Community Foundation).

Funds collected through a public benefits charge have almost always been established on a volumetric (i.e., cents/kWh or percentage of revenue) rather than fixed ($ per customer per year) basis. Charging in proportion to the amount of energy consumed treats ratepayers equitably and minimizes distortions to electricity rates.

Program Administration: As shown in Table 3, three different types of PBF administrators are prevalent in the United States. State (or quasi-public) agencies are most common (11 funds in ten states), followed by utilities (four funds in three states) and independent non-profits (seven funds in three states). Though state governmental administrators outnumber the other two types, they are not necessarily a better (or worse) choice than utilities or non-profits; experience shows that dedicated staffing levels, experience and capabilities, and enthusiasm are more important determinants of program success than affiliation.

Utility company administrators are often very capable, efficient, dedicated, and accountable. However in some cases, they have been perceived as having potential conflicts of interest, imposing excessive legal and technical review of funded projects, being resistant to distributed generation, and underestimating their administrative responsibilities or having inadequate accountability.[33] Partly as a result, in at least one instance the state public utilities commission has stepped in to take over administration of a portion of the state's renewable PBF from the utilities.[34]

State agencies and non-profit entities are usually excellent program administrators, but are not without their potential pitfalls. Governmental administrators may be constrained (e.g., due to budget limitations) in their ability to hire good staff to handle the workload associated with administering a PBF. PBFs administered by governmental agencies may also be more vulnerable to political pressure, or even budgetary raids. Non-profit administrators may have accountability and oversight issues, and newly formed non-profits created specifically for the purpose of PBF administration (as in Oregon) could incur substantial startup costs.

The choice of PBF administrator is best considered on a case-by-case basis, with consideration given not only to the absence or presence of existing organizations or infrastructure capable of effectively administering the fund, but also to the scope and funding duration of the PBF.

[33] In at least three of the four funds using utility company PBF administration, state public utilities commissions or environmental advisory councils provide a relatively high degree of oversight.

[34] The solar photovoltaic buy-down program funded by New Jersey's Societal Benefits Charge was originally administered by the state's electric utilities. After a program evaluation conducted by an external entity, the NJBPU decided to take the PV program under its own Clean Energy Program. For more information, see http://www.bpu.state.nj.us/wwwroot/energy/EO99050348ORD.pdf

Use of PBF Funds: Renewable PBFs in the United States have implemented a wide variety of renewables programs, including:

- Financial incentives for large-scale projects;
- Rebates and buy-down incentives for distributed generation;
- Consumer loan programs;
- Project and company financing;
- Support for green power marketers;
- Consumer education; and
- Small grants for business development, feasibility studies, workshops, conferences, and other activities.

Some of these programs (e.g., incentives for utility-scale projects, distributed generation buy-downs) are primarily targeted at installing as much renewable generation capacity as possible in the near term. Others (e.g., consumer education, business development grants, and support for the green power market) are focused on market transformation that is more long-term in nature and could ultimately lead to a more sustainable market for renewable energy technologies.

Metrics of Success

The broad array of PBF programmatic activity has complicated the establishment of useful metrics of success. The most straightforward metric is installed renewable energy capacity. This metric, however, can be at odds with market transformation programs that may favor lower direct subsidies and more infrastructure-building activities. Such market transformation programs are typically of a much longer-term nature, requiring patience and a more complex approach to program evaluation. Failure to clearly resolve these tensions can make ongoing progress difficult to measure and evaluate, as well as subject to political pressure based on the need to justify expenditures.

In spite of these tensions, most funds have set goals, and measure their success by, one or more of the following metrics:

- **Renewable capacity:** MW of new renewable capacity supported by the PBF
- **Renewable energy:** MWh of new renewable generation, or percentage of the state's load supplied by renewable generation, supported by the PBF
- **Emissions:** Reduction in emissions of CO_2, SO_2, NOx, mercury, and particulates attributable to projects supported by the PBF
- **Economic development:** Number of jobs created, number of new renewable energy businesses in the state, and/or increase in the tax base attributable to the PBF

The Energy Trust of Oregon (the non-profit administrator of Oregon's PBF) has set a goal to meet ten percent of Oregon's electricity load through renewable generation by 2012. This translates into support for 450 average MW of new renewable generation; according to its 2004 annual report, the Energy Trust is nine percent of the way towards meeting this goal.

The Massachusetts Technology Collaborative (the quasi-public administrator of Massachusetts' renewables PBF) has a goal of supporting the installation of 750-1000 MW of new renewable capacity by 2009. This goal overlaps considerably with the state's renewables portfolio standard (RPS), which will require the construction of around 500 MW of new renewable capacity by 2009 and shows the complementary role PBFs and RPS can play.[35]

New Jersey's 2003 PBF annual report lists specific long-term goals of supporting 300 MW of new, in-state renewable capacity by 2008 and increasing in-state solar generation to 120,000 MWh/year by 2008.[36] Other metrics cited include annual and projected lifetime generation from new renewable capacity supported through the program, as well as emissions reductions.

Best Practices

Although experience with renewable PBFs in the United States is still relatively limited (the first few funds began operating in 1998, and some have only been active for a few years), best practices concerning the creation and implementation of a PBF are beginning to emerge, and can be grouped into three categories: creation, score and administration.

PBF Creation

- Absent other opportunities (e.g., utility merger or environmental settlements), finance the PBF through a volumetric charge on electric bills in a way that is competitively neutral and non-bypassable (i.e., consumers cannot avoid paying the charge by switching electric suppliers).

- Set the funding level as high as is politically feasible. At current funding levels in the United States, public benefits likely far outweigh the costs. Under-funding limits the programmatic opportunities available to a program.

- Provide long-term funding stability. Because it takes time to implement programs effectively and build markets, a minimum of five to seven years of funding stability should be provided. Shorter funding cycles could preclude risk-taking and implementation of multi-year programs aimed at market transformation.

- Insulate the fund from budgetary raids. Involving a wide variety of stakeholders in the creation of the fund could help to build political support. A dedicated source of funds (e.g., an electricity surcharge) might be less vulnerable than funding from more

[35] Compliance with the RPS is behind schedule due to a lack of long-term contracts and hence financing available to eligible projects. In response, Massachusetts' renewable energy fund has stepped in to offer various forms of ten-year price insurance for renewable energy credits. This guaranteed revenue stream has, in some instances, been sufficient to enable projects to proceed.

[36] As is the case in Massachusetts, the goals of the New Jersey PBF are somewhat intertwined with those of New Jersey's RPS (which includes a solar set-aside). By setting the dual goals of increasing capacity (presumably from utility-scale projects) *and* increasing solar generation, New Jersey has reduced some of the tension between large (e.g., utility-scale wind) and small (e.g., rooftop PV) projects–both types of projects will be required to meet the PBF's goals.

indiscriminate governmental sources of money (e.g., settlement funds). Minimizing carryover of funds from one year to the next may make for a less-tempting target. Finally, legislative language that authorizes the use of funds only for specific purposes (as in California) can be helpful, but still may not prevent the government from "borrowing" the funds under an indeterminate repayment schedule, or altering the legislation to allow a broader re-appropriation of funds.

Programmatic Scope

- Clearly define which renewable resources and technologies are eligible for PBF funding. Use of general terms such as "biomass" or "customer-sited" can, without further clarification, create funding uncertainties, and potentially generate legal action, that could disrupt or delay the development of entire industries.
- Provide clear guidance for the allocation of PBF funds across resource or technology groups to avoid fighting among different renewable energy industries (e.g., solar vs. wind). At the same time, PBF administrators should retain sufficient flexibility to shift any prescribed allocation of funds in response to changing market conditions or emerging opportunities.
- Geographic restrictions (if any) on where funded projects can be located should be defined within the context of in-state renewable resource availability as well as the structure of the electricity market. For example, if the electricity market is regional in nature (e.g., as in New England), then funding for out-of-state projects within the region might be acceptable. PBFs can require that power and/or RECs from funded out-of-state projects be delivered into the state to ensure that at least some of the project's benefits accrue to in-state ratepayers.
- Allow the fund administrator sufficient flexibility to choose the types of programs it will offer, as well as the types of funding recipients it will target. For example, one PBF in the United States is only able to offer consumer loans, while another is only able to fund non-profit organizations; both have found these severe restrictions to be detrimental to their overall mission.
- Set clear and reasonable goals from the start, but also allow the fund to shape the measurement and evaluation process to reflect the types of programs that it offers. Early and clear demonstration of program effectiveness and success through independent evaluation may help protect PBFs from budgetary raids.
- Seek out and encourage regional coordination with other state PBFs. Most funds, particularly those within the same region, share common needs and experiences and could learn from other funds, as well as benefit from the potential economies of scale that regional coordination might provide. In the United States, the Clean Energy States Alliance serves as a conduit for information-sharing and joint project activity among renewable PBFs.[37]

[37] http://www.cleanenergystates.org/

PBF Administration

- Carefully weigh the pros and cons of different administrative options. The presence of adequate, experienced, capable and dedicated staffing is likely to be a more important determinant of success than whether the fund is administered by a utility, a government agency, or a new or existing non-profit organization.
- Identify a single entity charged with oversight of the PBF administrator and clearly define the extent of oversight responsibility and authority. Without a clear "chain of command," PBF administrators may feel compelled to answer to multiple interests (e.g., the PUC, the legislature, the governor), thereby needlessly adding to the administrative burden.
- To avoid under-staffing, designate (and perhaps set limits on) explicit funding for administrative costs. On a percentage basis, it is not uncommon for 5-10% of PBF funds to be used to cover administrative and management costs. Some funds have set limits on the proportion of the fund that can be used for such costs. Xcel's Renewable Development Fund has a 5% cap in place, NYSERDA has a 7-8% cap, and Oregon caps administrative costs at 11% of funds (but currently only spends about half that much).

Conclusion

In the United States, PBFs were originally created as a relatively simple way to equitably collect revenues to continue public benefits programs that might go unfunded in a restructured or competitive electricity industry. However partly due to their success and simplicity, PBFs are now considered appropriate for either restructured or conventional utility systems. Although renewable PBFs have been important to the commercialization of renewable energy technologies in the United States, they are not a panacea for all barriers to renewable energy. While PBFs are able to support small distributed generation technologies (e.g., rooftop PV), modest funding levels and an inability to offer power purchase agreements will limit the ability of PBFs to support large, utility-scale projects (e.g., wind farms). Therefore, PBFs should be deployed in combination with, rather than in lieu of, other policy approaches. Many states with both a renewable PBF and an RPS are finding that the two complement, rather than compete with, each other. In this way, PBFs can be an important element in a portfolio of policy approaches deployed to bring renewables into the mainstream.

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Public Benefit Funds & REC Ownership

As one of many state policies which support renewables, PBFs often intersect with some of the other green tariffs discussed in this handbook, including tariffs to support green power (or green pricing) programs, as well as renewables portfolio standards (RPS). This intersection raises administrative questions, in part related to potential concerns over "double-dipping":

1) Should PBF-funded projects be allowed to command a price premium in the green power (or green pricing) market?
2) Should PBF-funded projects be allowed to benefit from the sale of renewable energy credits (RECs) into an RPS compliance market?
3) Should RECs from a PBF-funded project belong to the generator, the utility buying the power, the PBF itself, or the ratepayers who fund the PBF?

Most state Public Benefit Funds have affirmatively answered the first two questions. In fact, many PBFs provide financial support not only to renewable generators, but also to those who purchase or market green power. These PBFs view their simultaneous support of both renewable supply and demand as a way to create a long-term sustainable market for renewables. Similarly, several state PBFs have assumed an important role in jump-starting RPS policies suffering from an early lack of supply (e.g., Massachusetts), or in funding the above-market cost of the RPS (e.g., California). In both cases (i.e., the intersection of PBFs with green power and RPS markets), there appears to be little if any concern on the part of PBFs that funded projects might be receiving financial support from multiple sources, as long as the other policies or markets involved do not prohibit multiple incentives, and public policy goals are being met.

Of more concern is whether PBF funding is providing benefits to in-state ratepayers. One way that state PBFs have sought to ensure the delivery of ratepayer benefits is to require funded projects to sell at least some minimum portion of their RECs to in-state (as opposed to out-of-state) voluntary or compliance markets. This practice is particularly prevalent in the Northeastern United States, where some state PBFs share a common regional electricity market.

One notable caveat on the second question is Wisconsin's PBF, which was designed to target demand-side applications for renewable energy as a way to complement, rather than overlap with, the state's supply-side RPS. In addition, Wisconsin's PBF prohibits funded projects from selling RECs into Wisconsin's RPS compliance market for ten years.

State PBFs have taken several different positions on the third question. Connecticut's PBF strongly encourages (through greater likelihood of success in competitive solicitations) projects to agree to transfer some or all RECs to the PBF if funded. Other PBFs, e.g., those in Montana, Oregon, Austin (Texas), and Minnesota, require funded projects to convey some or all of their RECs to the PBF. Still others (e.g., Massachusetts, Illinois, Rhode Island) purchase RECs from renewable generators as a means of providing financial support. And yet others specify that the RECs remain with the generator (e.g., Washington).

Reasons for claiming title to RECs vary. Oregon's PBF believes that only by claiming and retiring RECs (in proportion to the amount of above-market costs funded by the PBF) can it fulfill its obligation to deliver the benefits of renewable energy to Oregon ratepayers. Connecticut's PBF, on the other hand, views RECs as a valuable commodity that, when re-sold into the market, can help to fund its programs on an ongoing basis. Other PBFs, typically those administered by utilities, claim title to funded projects' RECs as a way to help meet current renewable obligations (in the case of Austin Energy in Texas and Xcel Energy in Minnesota) or hedge against future (in the case of North Western Energy in Montana) renewable energy goals or mandates.

Text box continues on next page

Regardless of their position on REC ownership, all state PBFs are concerned about the potential double-counting of RECs in the marketplace, and several have helped to fund the development of state or regional REC tracking, accounting, and verification systems to combat potential abuse. It is important that there is only one claim being made on ownership of any MWh of renewable energy attributes (RECs) from a PBF-funded project. Because there may or may not be ownership of RECs being taken in exchange for the PBF funds, and there may be one or more PBF revenue streams associated with a project, it is important that the ownership of RECs from the project be understood and articulated to avoid double claims. REC tracking systems will help avoid double claims because ownership must be specified for the REC to be placed into an account and tracked.

For additional information on the interaction between PBFs and RECs, see Fitzgerald et al. (November 2003) and Hamrin et al. (May 2003).

C. Net Metering

Overview

Net metering, for consumers with generators on their side of the meter, allows electricity to flow in either direction through a bi-directional meter. When the customer's generation exceeds his/her use, electricity from the customer's facility flows into the utility's distribution grid.

Net metering has many purposes:

- Promoting small-scale renewables,
- Enhancing the market for renewables,
- Facilitating installation and interconnection of on-site generation,
- Reducing customers' electricity bills,
- Empowering customers to manage their electricity usage, essentially storing excess power on the grid for use at a later time, and
- Lowering the utility system peak demand.

Distributed generation, similar to a demand reduction strategy, can provide valuable benefits to the utility and all its customers: peak-power demand reduction, avoided distribution and transmission system losses and investments, avoided fuel/operations/maintenance of existing generators. It also provides environmental benefits to all customers.

Net metering laws have been enacted in 39 states and the District of Columbia (D.C.). Because they are based on the same general concept, there is great similarity in language of these statutes. There are also many differences in specific elements, e.g. sizes of allowable systems, customer classes allowed to participate, buyback rates, accounting treatment of surplus generation, and disposition of accumulated excess power.

Net metering can apply to any renewable technology or fuel. It most commonly applies to solar electric and small wind generators but in some states may include on-site small biomass/cogeneration systems and micro-hydro systems. It is particularly important for small, on-site solar and wind installations. Fuel cells and, in some cases, small cogeneration are eligible for net metering in about ten states.

The table on the next page summarizes net metering programs in 39 states and 21 utilities.[38]

[38] www.dsireusa.org

Table 4. Summary of Net Metering Rules*

	States:[39] (Total 39 plus D.C. minus 4 utility-only rules = 36)	Individual Utility Rules Listed: (Total 21)
Applicable Customer Classes** The majority of states include residential, commercial and industrial sectors. Three states do not allow industrial and 4 states include agricultural and other. [40]	R/C 3 R/C/I 29 R/C/I/O[41] 4	R only 3 R/C 9 R/C/I 6 R/O 3
Capacity Limit[42] Eighteen states limit the size of facilities to <25 kw while 13 states allow systems >25 kw.	10kw 6 25kw 12 >25kw 13 Unknown 6	10kw 11 25 kw 7 >25kw 3
Limit on Availability Nineteen states have no limit on the availability of net metering while 14 states limit the size of the market that can use net metering. Where it exists, the limits range from 0.05% to 1% of peak load.	No 19 Yes 14 Unknown 4	No 11 Yes 10
Inter-connection Standards *** Only 8 states do not presently include interconnection standards in their net-metering rule.	Yes 12 No 6 Unknown or in process 5	Yes 19 No 1 Unknown 12 Under Development 2
Buy back of Excess Twenty-nine states credit excess to customer's next bill, 16 states grant excess to utility at end of 12-month billing cycle. Six states purchase excess (monthly or annually) at avoided cost rate while only two states (MN, WI) purchase at retail rates and 4 others purchase excess at some discount of retail rates. Only one state (AK) grants excess monthly to the utility.	No 23 Yes AC or wholesale rate 8 Full Retail 3 Not Specified or TBD 2	No 14[43] Yes AC or wholesale 4 Full Retail 2 Not specified 1

* R = Residential C = Commercial I = Industrial O = other
AC = avoided cost

** At least three states have not yet completed their rulemaking and six states' rules vary by utility. Therefore the totals will not be consistent with number of states with net-metering laws.

*** The FERC has now issued Model Interconnection Standards for small generators that would apply (1) where states do not have such standards; or (2) where state standards do not meet the model rule criteria.

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[39] This summary covers 39 states + Washington D.C. and 21 individual utilities. Four states seem to have permissive laws with individual rules utility by utility.

[40] The "other" includes such things as Agriculture, Schools, Government, Institutional, and/or NGO facilities.

[41] The "other" includes such things as Agriculture, Schools, Government, Institutional, and/or NGO facilities.

[42] This is the limit on the size of residential systems. Some states also have separate limits on the size of commercial, industrial, or agricultural systems.

[43] Two do not credit at the full retail rate.

For more detailed information on individual state rules, the Interstate Renewable Energy Council has compiled a table summarizing each state's net metering rules.[44]

The Energy Policy Act of 2005 (EPAct 2005) requires electric utilities to make net metering services available to any electric customer upon request. The state regulatory authority is required to consider net metering by September 2007 and must adopt net metering provisions by September 2008; assuming they have not previously enacted such provisions, conducted a net metering proceeding to consider the standards or are in a state in which the state legislature has voted on the implementation of such standards.

California's Carbon Risk Adder

Under a new approach to the evaluation of fossil generation in general procurement,[45] California's investor-owned utilities will add to each bid a value (ranging from $8 to $25 per ton) for the amount of CO2 that would be emitted by a fossil-fuel generating unit. This adder represents an estimate of the likely cost of purchasing CO2 offsets to comply with future mitigation regulations. By internalizing this risk in the evaluation of fossil bids, renewable and demand-side options will be more economical and the output of CO2 associated with meeting California's electricity needs will be reduced.

Program Details

Ease of Installation: A good net metering program streamlines and simplifies the process by which customers can deploy renewable energy on their properties. Interconnection, inspection, and operation are no longer a barrier to the installation of on-site generation with good net metering rules and a cooperative utility. However, eight states do not include streamlined connection standards in their net metering rules and others have yet to complete such standards.

The new FERC Small Generator Model Interconnection Standards will influence these states and can act as a starting point or template for state standards. EPAct 2005 requires electric utilities to interconnect distributed generation customers upon request. The Act requires that interconnection rules must conform to IEEE Standard 1547. State regulatory authorities must consider these standards by September 2006 and must complete them by September 2007. However, states that have already enacted interconnection standards, have conducted a proceeding to consider the standards, or in which the legislature has voted on the implementation of such standards do not have to meet these timelines.

[44] http://www.irecusa.org/connect/statebystate.html
[45] CPUC docket # R.04-04-003; D.04-12-048. See: http://www.climatechange.ca.gov/policies/state_roles.html

Treatment of surplus generation: A key feature of net metering is the ability to virtually store power on the grid. When a customer/generator produces more power than he/she consumes in a billing period, the power disappears into the grid, but the amount of the surplus is accumulated in the customer's account. In a subsequent billing period, if the customer consumes more than he/she produces, the accumulated surplus is used to offset the shortfall.

Three states allow this generation credit storage only over a one month period; two states and seven utilities appear to allow the surplus to be rolled over to the next month on an indefinite basis; but in most states, customers have a maximum of twelve months to use any excess power generated by their systems.

At the end of the storage period, the accumulated amount can be zeroed, in essence granting the power to the utility free of charge. Or, the customer can be compensated for it by the utility. Twenty three states and 14 utilities grant the excess power to the utility free of charge. Eleven states and six utilities require the utility to purchase any excess power at the end of the allowable storage period. Only two of these states (and two utilities) pay the customer the full retail rate. The other nine states (and four utilities) buy the power at either avoided cost or some other wholesale or discounted rate.

Compensation for surplus power depends on the purposes of the program. If the utility is interested in increasing local supply, offsetting peak load, or for distribution or transmission reasons, then purchasing any excess power from customer/generators will encourage them to build facilities larger than necessary to serve their own needs. How much larger will depend on the buy-back price, which depends on the value of that power to the company.[46]

Many PV and small wind systems generate excess power during peak periods, with the customer using the stored power at night and in other off-peak times, thus providing a benefit to the utility and its non-participating customers. The excess power may also contribute to increased stability on some distribution systems. Depending on the utility's circumstances customer-generated power may be worth the full retail rate or more.[47]

If the goal of the program is to facilitate the installation and use of on-site generation to serve the customer's own load, granting any excess power to the utility at low or no rates will encourage customers to size their systems to more closely match their loads.

[46] Utilities could implement geographically specific buy back rates depending on the needs of the distribution system or they could only purchase excess power during peak periods. So far, these options have not been pursued.

[47] A report, spearheaded by Americans for Solar Power (ASPv) quantifies 14 key areas where distributed PV power provides added value to ratepayers, the electric grid, and utilities, totaling from 7.8 to 22.4 cents/kWh. See www.forsolar.org.

Metrics of Success

The number of systems installed (or the total MW installed) is an important indicator of Distributed Generation (DG) activity in a net metering state. However, this metric could also reflect other incentive programs available to the customer (e.g. rebates from PBFs or tax credits).

Another measurement of success of a net metering program is the ease of installing an on-site, DG system. Success is the local utility providing a smooth process for interconnection, as simple as having a meter installed.

Misconceptions
The following misunderstandings can lead to poor net metering implementation.

- ***DG power is unsafe and of poor quality.*** In the early years of net metering there were fears that utility linemen would be jeopardized by customer-owned generators that were producing power when the distribution grid was being repaired. However, today's power electronics safely disconnect generators from the grid when it is de-energized. Also, modern power electronics, controllers and inverters provide a level of power quality and power safety that easily meets utility standards for preserving the integrity of the grid.

- ***DG is unfairly subsidized by other customers.*** In utility systems where the cost of using the distribution and transmission systems is a volumetric charge on the kWh a customer uses, net metered customers may not be contributing their fair share to the costs of operating the utility distribution system. However, the impact of net metering on the electricity rates of other customers may be much less than the benefits. For example an analysis of the value of PV to the electric utility system[48] (including such things as avoided distribution and transmission costs, avoided generation capacity capital costs, avoided air emissions, avoided generation T/D losses, etc.) indicates that the range of total value of distributed PV is between 7.8 – 22.4 ¢/kWh. No definitive analysis has been conducted on the cost of lost distribution revenue but any such analysis should net this lost revenue against the non-energy value provided by net-metered facilities to determine the true impact.

- ***Net metering pays a retail rate for a wholesale product.*** Most net-metering laws are designed to support the offset of the owner's usage and most DG owners design and size their systems to do just that. If the system generates excess power significantly above what the owner uses, they might either grant the power to the utility or be paid for it. A few state net metering programs pay back at retail rates or avoided cost/wholesale rates, but the majority (37 states/utilities) rolls forward the excess generation or the excess is granted to the utility at the end of the storage period.

[48] "Build-up of PV Value in California" submitted to the California PUC, Exhibit LSS-7, RI 4/13/05.

Best Practices

1) **Think of distributed generation as demand reduction rather than supply.** The delivery of excess generation back to the grid is often incidental to the electricity customer. On average, more than half of the self-generated power is used instantly to serve the customer's load. The other half is netted back to the utility (often during peak hours) and then taken back by the customer during off-peak hours or off-peak months. It is helpful to the deliberations on net metering implementation to think of DG in the same manner as energy efficiency – as a demand reduction strategy rather than a supply strategy. Net metering reduces the size of the load the electric utility must serve.

2) **Tailor capacity limits and terms for different customer classes.** Many states have limits on the amount of capacity that can be net metered and some states limit the customer classes that can participate in net metering. But most customer classes can benefit from net metering and at the same time benefit the system and other customers. If you consider distributed generation as being like demand reductions from energy efficiency, then capacity limits may take on new meaning.

3) Make goals and objectives clear.
If a goal is to acquire additional resource supply, then purchasing excess power at the end of the storage period may be proper. If a goal is to help customers more easily install on-site generation for their own use, then granting any excess to the utility may be a good strategy to encourage proper sizing of systems.

4) Match tariff rates and program goals.
Net metering tariffs (credits to customer's bills, value of storage of excess power, and any buy-back rates) should be fair and consistent with program goals.

5) Consider the effect of demand charges.
Customers with demand charges, e.g. irrigation or commercial classes, may see little benefit from net metering depending on the coincidence of generation and load. Demand charges may have to be adjusted to reflect the customers' circumstances and their effects on the system.

6) Consider both costs and benefits attributable to net metering.
What are the costs to other utility customers attributable to net metering? Some utilities tend to attribute virtually all the revenue impact from DG to net metering as though all DG energy savings are an economic loss.

Even in the absence of net metering, customers are entitled (through PURPA) to interconnect, get retail rate credit for the power they use on site and sell back any excess to the utility. Therefore, the actual revenue impact equals the difference between the retail price normally paid by the customer and the avoided cost price times the number of kilowatt-hours delivered to the utility grid. The actual revenue impact has to do with the net exchange of DG energy between the utility and the customer not the total amount used by the customer.

Conclusion

Early adopters will be motivated to net meter. But most other customers need something more to help overcome the economic and other barriers to small on-site generation. Net metering alone is an important but insufficient strategy. Therefore, many states combine net metering policies with other types of DG incentives. Distributed generation, similar to a demand reduction strategy, can provide valuable benefits to the utility: peak-power demand reduction, avoided distribution and transmission system losses and investments, avoided fuel/operations/maintenance of existing generators. It also provides environmental benefits to all customers. Net metering is a means for facilitating on-site generation. Good implementation requires rules that are fair and equitable to all parties and support the types of benefits intended by the law.

Washington State's Feed-In Tariff

The state of Washington recently adopted a European-style feed-in tariff for renewable energy. Senate Bill 5101, signed in May 2005, that established a production incentive of 15 cents per kilowatt-hour for electricity from solar, wind and anaerobic digesters, capped at $2,000 per year per system (which is equivalent to the annual output of a typical 3.5 kW solar photovoltaic system). This is the first such production incentive offered in a U.S. state.

The tariff is adjusted upward using a multiplier if the electricity is generated in-state, using an inverter manufactured in-state, or using equipment manufactured in-state. This can raise the tariff to as high as 54 cents per kWh; this rate would be available for 10 years, beginning July 1, 2005.

Initially, the incentive applies only to off-grid power sources but will be open to grid-tied systems when energy companies serving eighty percent of the total customer load in the state adopt uniform standards for interconnection to the electric distribution system.

Utilities are not obligated to offer the tariff, but, participating utilities are allowed to write off the cost of providing the credits against their state taxes.

One advantage of this tariff over traditional capacity-based rebates is that it creates an incentive to generate renewable energy over time, not just to install a renewable energy system. This addresses the issue of some rebate-style incentives that resulted in renewable facilities that do not maximize output potential, sometimes due to poor maintenance.

The tariff specifies that the environmental attributes of the renewable energy system belong to the generator and do not automatically transfer to the state or the utility.

D. The Interaction of Green Tariff Programs: Avoiding Double Counting, Improving Results

Interaction of Green Tariff Programs

There are many tools that can be used to stimulate renewable energy development. As this handbook has articulated, the tools vary from voluntary mechanisms for residential and non-residential customers to mandated requirements for regulated utilities. In order to meet various goals, the different tools are used for different purposes.

Green pricing programs empower customers to make energy supply choices, while providing important environmental and cost-stability benefits. They are also a means of educating customers about the sources of electricity they use. Net metering programs provide a means for customers to install their own renewable energy generating equipment. Renewable portfolio standards socialize the costs and benefits of renewable energy among all ratepayers.

Regulators may wonder which of these renewable energy programs would best serve the ratepayers in their state. Since these programs address different goals, a combination of complementary programs rather than one single program is often the best solution. The ultimate answer depends upon the state's renewable energy goals.

Program Selection Process

In order to identify the general mix of programs required to meet a state's renewable energy needs, consider the following process:

- Identify the target power sectors you are trying to stimulate and the associated goals, for example:
    - Utility renewable bulk power supply to:
        - Hedge against electricity rate volatility due to fossil fuel price fluctuations;
        - Diversify the supply mix;
        - Reduce air and greenhouse gas emissions;
        - Hedge against potential future carbon emissions reduction regulations;
        - Spread the costs and benefits equitably over all the customer base;
        - Establish a stable market for renewable energy.
    - Distributed generation to improve utility operations to:
        - Defer distribution/transmission-line upgrades;
        - Reduce distribution costs.
    - Distributed generation on the customer's side of the meter to:
        - Serve the needs of customers that wish to self-generate;
        - Simplify interconnection of self-generation facilities;
        - Encourage (or discourage) additional supply from on-site generation.

  - Voluntary renewable energy purchases by customers that want to go beyond utility renewable electricity levels to:
    - Serve the needs of customers that wish to voluntarily purchase renewables beyond the amount provided by default from their electricity supplier;
    - Provide renewable energy as a hedge against electricity price fluctuations for those customers willing to voluntarily pay for this service.
- After identifying the target sectors and purposes, identify the types of renewable programs appropriate to each. For example:
  - Utility renewable bulk power supply
    - Integrated Resource Planning
    - Renewable Portfolio Standard
    - Feed-in Tariff
    - Greenhouse Gas Cap & Trade Program
  - Voluntary renewable energy purchasing programs
    - Green pricing
    - Green check-off
- Pair the program characteristics with the sector goals and select the type of program or programs that are likely to meet your goals. Continue this process for each of the identified sectors.

Each renewable energy program should have a specific purpose(s). It may not be necessary to have multiple programs serving the same purpose.

Avoid Double Counting

Key Principles: It is all right for one program to serve multiple purposes. It is also all right for one project to receive funding support from more than one source (e.g. from federal production tax credits and from a state clean energy fund) as long as this is allowed under the programs' rules. However, in most cases it is best to ensure that:

1) A MWh of renewable energy may only be credited for one end-use purpose (e.g. it may be used by a utility to meet their RPS compliance target <u>or</u> it may be used in the voluntary market by an end-use customer). There can be only one "claim" made on each MWh of renewable power and then it is retired.
2) The utility is not receiving additional payment for MWhs that have already been recovered through rates. Or if they do, the ratepayers are reimbursed by the utility for this outside payment (sale).
3) A utility that has purchased power from a renewable facility but has not purchased the renewable energy certificates (or has sold off the RECs) may not claim the residual power as being "renewable."

Best Practices

- Accepting more than one incentive payment or subsidy does not constitute double counting or double ownership. For example, a wind farm developer receiving a federal Production Tax Credit does not result in the federal government being assigned ownership of the RECs from that facility. A facility owner can, in some cases, receive multiple payments or incentives without being party to double counting or double ownership. The Key Principles outlined in the preceding paragraph provide some guidance on this topic.

- Initially RECs should be considered to be the property of the owner of the renewable energy facility. They can be transferred to another party by contract or law.

- Incentive payments or rebates to renewable energy projects from public benefit funds may require a pro-rata share of the project's RECs as a quid pro quo for receiving the incentive. Such rules or requirements should be prospective only so that project owners can make informed decisions concerning the value of the incentive.

- Renewable energy tracking systems will help prevent double counting and make project accountability more transparent.

- Voluntary and mandatory programs should be complimentary and not thought of as substitutes for each other.

- Megawatt hours resulting from green pricing programs and Renewable Portfolio Standards should be counted separately.

Conclusion

Renewable energy resources - energy sources that are replenishable and replenished on some reasonable time scale[49] - are available nationwide. Every state has one or more type of renewable energy resource available, with the potential to offer customers clean, affordable power. While the economics and performance of renewable energy facilities have been improving substantially in recent years, there is still a place for regulators and policymakers to encourage programs that foster nascent renewable energy markets.

Some states have taken aggressive approaches to stimulating renewable energy markets through an array of programs. Many of those programs have now proven successful. Looking at the top five states in terms of non-hydro renewable generation[50], four of those states (California, New York, Massachusetts and Pennsylvania) have implemented a variety of renewable energy programs and tariffs. Those four all have renewable portfolio standards, public benefits funds,

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[49] National Association of Attorneys General's Environmental Marketing Guidelines for Electricity. http://www.naag.org/issues/pdf/Green_Marketing_guidelines.pdf
[50] Energy Information Administration. Renewable Energy Annual 2003. http://www.eia.doe.gov/cneaf/solar.renewables/page/rea_data/tablec1.html

and net metering standards. They are also states that are home to some of the most vibrant voluntary markets in terms of green pricing programs and green check-off programs. This is a demonstration of how the combination of a number of renewable energy programs can aid the burgeoning market for renewable energy.

Each of the programs described in this handbook offers its own benefits for program participants and ratepayers. Each program also has its own associated costs (or savings) for program participants and ratepayers. Each state can learn from the experiences of others through the observation of their successes or shortcomings with those renewable energy programs and tariffs. Through the development of a portfolio of successful renewable energy programs nationwide, all ratepayers will benefit from a cleaner environment, affordable power, and price stability.

Taking RECs in Exchange for Financial Incentives

Should utilities offer rebates or special rates in exchange for acquiring RECs from projects that receive the rebates? This issue is similar to the issue raised in the section on Public Benefits Funds and the disposition of RECs from PBF-funded projects. Several utilities now offer this deal as the quid pro quo for receiving the rebate or special incentive as outlined below.

Public Service of New Mexico (PNM) proposed a new "customer solar PV program"1 aimed at increasing the amount of solar energy generated in the state as part of the utility's 2006 Renewable Energy Procurement Plan. Under the program, PNM would purchase the RECs associated with electricity generated by customers who own their own grid-tied, 10-kilowatt and smaller photovoltaic (PV) systems. PNM would credit participants' monthly bills 11 cents per kWh of RECs for the energy produced. In addition customers will receive a kWh for kWh credit for all excess energy delivered to PNM's grid through net metering. PNM's current residential rate is 8.03 cents per kWh. The RECs would contribute toward the utility's RPS obligation.

We Energies of Wisconsin also filed for approval of an experimental buy-back rate for customer-sited solar PV. Under the three-year solar buy-back pilot, We Energies proposes to purchase the entire output of customer-sited PV systems between 1.5 kW and 100 kW at a rate of 22.5¢/kWh for 10 years, up to a total installed capacity of 500 kW. The solar output will be used to supply the Energy for Tomorrow green pricing program; solar system owners must be enrolled in the program to be eligible for the payments.

These tariffs can be a good way to encourage the development of renewable if some criteria are met. The two primary considerations are: 1) That the generators understand what it is they are selling and what the consequences are of selling their RECs in advance of making their choice; and 2) how the on-site generators describe the power they produce. As an example, say a commercial business installs a 5 kW photovoltaic system on his/her roof and sells the RECs to the utility in exchange for a favorable rate. Because the REC ownership is transferred, the business owner can no longer claim that the business is solar powered. But people passing by can clearly see the PV system on the roof and might even see the meter spin backwards when the sun is shining. How can it be that the business is not, in fact, solar powered? CRS recommends calling the business a "solar host" and asking the customer not to represent the building as solar-powered. This is may seem inconsequential or impractical, but it has ramifications on how the purchase of electricity devoid of RECs is described.

IV. CASE STUDIES

Case Study: Model Green Check-off Tariff

PACIFIC POWER

The Blue Sky green check off program offered by PacifiCorp is one of the most successful in the country. In 2004 Blue Sky was ranked second by the National Renewable Energy Laboratory in terms of total number of participating customers, third in terms of customer sales and had the sixth lowest price premium. The success of the Blue Sky program is likely due to the variety of options offered to customers in Oregon and the local connection with customers.

State	Oregon
Utility Name	**Pacific Power**
Utility Type	Investor Owned Utility; subsidiary of PacifiCorps Operating in OR, UT, WY, WA, CA & ID 1,569,831 Customers Overall 516,939 Customers in Oregon
Program Name	Blue Sky
Program Start Date	Blue Sky Block: 2000; Blue Sky Usage and Habitat: 2002
Blue Sky kWh Total	266,370,000 across all six states
Fuel Types Included	wind, biomass, solar
Renewable Product Mix	Blue Sky Block: 100% wind Blue Sky Usage: 38% biomass, 61% wind and 1% solar Blue Sky Habitat: 38% biomass, 61% wind and 1% solar
Customer Participation Rate	2.3% across all six states 3.6% in Oregon *Residential:* Block (system wide - six state service area) - 1.6% - Block (Oregon only) - 1.04% - Usage (Oregon only) - 2.5% - Habitat (Oregon only) - 0.57% *Non-Residential:* Block (system wide - six state service area) - 0.32% (includes <u>all</u> - commercial, industrial and irrigation customers) - Block (Oregon only) - 0.23% (available to <u>all</u> commercial, industrial and irrigation customers) - Usage (Oregon only) - 0.41% (only available to <u>small</u> commercial, industrial and irrigation only) - Habitat (Oregon only) -0.14% (only available to <u>small</u> commercial, industrial and irrigation only)
Green Power Charge	Blue Sky Block: $1.95 per block Blue Sky Usage: 0.078¢/ kWh Blue Sky Habitat: 0.078¢/ kWh + $2.50 directed towards salmon habitat restoration
How Product is Sold	Blue Sky Block: 100 kWh blocks Blue Sky Usage: 100% Blue Sky Habitat: 100%
Website	www.pacificpower.net
Contact Information	Virinder Singh virinder.singh@pacificorp.com

The Blue Sky green check off program offered by Pacific Power is one of the most successful in the country. In 2004 it was ranked second by the National Renewable Energy Laboratory in terms of total number of participating customers and third in terms of customer sales and had the sixth lowest price premium. The success of the Blue Sky program is likely due to the variety of options they offered to customers in Oregon and their local connection with customers.

Residential and small business customers can choose from three green options: Blue Sky Block, Blue Sky Usage and Blue Sky Habitat. Blue Sky Block is a 100 kWh block of new wind energy offered for $1.95 per block. Blue Sky Usage is comprised of 100 percent new renewable resources – a mix of wind, biomass and solar – offered for a premium of $0.0078 per kilowatt hour. Blue Sky Habitat is the same product as Blue Sky Usage, but also includes an automatic $2.50 monthly donation to a non-profit organization dedicated to the restoration of native salmon habitat.

Large business customers can choose either Blue Sky Block or Blue SKY QS. Blue Sky QS offers large energy users "Quantity Savings" for buying at least 101 blocks per month. The cost starts at $1.94 per 100 kWh block and is based on a sliding scale.

In 1999, Oregon's Electricity Restructuring Law (SB 1149) required Oregon's investor-owned utilities (PGE and Pacific Power) to offer their customers at least one renewable power option. In 2001, The Oregon Public Utility Commission (OPUC) approved new energy portfolio options, including green power, available to residential and small nonresidential customers of the state's two large investor-owned utilities beginning this fall. The OPUC approved three types of renewable energy options, which essentially correspond to green power products that were already being offered by the two utilities. More information can be found on their website at: www.puc.state.or.us.

Pacific Power launched the Blue Sky Block product in 2000 at $4.75 per 100 kWh block. The price was based on a break even analysis covering energy costs and basic program administration. The price did not cover paid media or marketing costs. Over time, this price decreased to $2.95 in 2001 and to $1.95 in 2003. This is entirely a cost-based program and not a money-making proposition.

The Blue Sky Usage and Habitat options were launched in 2002 in accordance with the electricity restructuring law. These options are marketed by a third party renewable energy marketer. The price of this program is based on the cost of the marketing services and energy offered by the third party. Regulatory proceedings require the utility to issue an RFP every three years. Regulators originally wanted to reissue the RFP every 18 months, but this causes too much uncertainty for the marketers The first contract was awarded to Green Mountain Energy in 2000 and the second contract was awarded to 3 Phases Energy in 2003.

The first RFP did not specify a cost, but requested that it be meet or beat the price for the block product. The RFP did specify that the price would include the cost of the supply, marketing and profit for the third-party vendor. The RFP did specify that a certain percentage should go to marketing costs. The amount customers pay goes straight through to the third-party vendor. The cost of customer service and the actual process of customer acquisition, but not marketing, is born by the utility. The second RFP specified that the price would be $0.0078 per kWh since that was the original cost of the product.

Pacific Power evaluated the proposals it received based on pricing and product content, newness of the renewables, location of the facilities and the third-party vendor's ability to market the program. While Pacific Power created the evaluation matrix, they had to present it to the OPUC prior to release. Also, once a winning proposal had been chosen, the utility had to send the decision process and scoring matrix to the OPUC for review.

Pacific Power is not required to do an annual review of the green power rates or an annual decrease. They cannot afford to lower the price further. When they lowered the price in the past, they did see a spike in enrollments, which could be attributable to that rate decrease.

Two aspects that have made their program successful are the variety of options offered to customers and the locality of their power resources. Different customers are attracted to different programs. In general, the usage option is more popular with residential customers because they can understand it better, while the block option is more popular with large residential customers because it is a fixed price month-to-month. Also, it is important to know what resources are available locally and would be appealing to customers.

Case Study: Model Green Pricing Tariff

Austin Energy has one of the most successful Green Pricing programs in the country, supporting more new renewables than any other program in the country. It was ranked number one in sales by the National Renewable Energy Laboratory in 2002, 2003 and 2004. Also in 2004 it was singled out as Green Power Program of the Year at the Fourth Annual Green Power Leadership Awards, presented by the Environmental Protection Agency, Department of Energy and Center for Resource Solutions.

State	Texas
Utility Name	**Austin Energy**
Utility Type	Municipal utility with 360,000 metered customers
Program Name	GreenChoice
Program Start Date	2000
Capacity of Program	226 MW
GreenChoice kWh Total	382,987,552
Fuel Types Included	wind, landfill gas, hydro, solar
Renewable Product Mix	79% wind, 19% methane, 1% hydro and solar
Customer Participation Rate	residential: 2.4%, commercial 1%
Green Power Charge	$0.033/kWh
How Product is Sold	Residential: 100% renewable Commercial: above 700,000 kWh, 10% of load
Standard Fuel Charge	$0.02796
Website	www.austinenergy.com/greenchoice/
Contact Information	greenchoice@austinenergy.com

One of the reasons Austin Energy has had a successful green pricing program is because of its innovative and unique rate structure. Participants in the GreenChoice program see the electric bill standard fuel charge (currently 2.80 cents per kWh, but is subject to fuel adjustment) replaced by a GreenChoice charge of 3.30 cents per kWh of electricity used. This means that customers typically pay about one-half cent more per kWh to help support the renewable energy power provided by GreenChoice. The flat green rate provides customers with a price hedge against volatile fossil fuel prices; the Green Choice rate is a fixed rate. While fossil fuel prices are unstable, their product is offered at a fixed rate. GreenChoice's largest resource consists of new wind turbines in West Texas. The program also receives electricity from four new landfill methane gas projects located around Texas. Austin Energy has signed 10-year contracts for electricity from the wind and methane gas projects outlined above. The price for that electricity will remain the same for the life of those contracts, allowing GreenChoice customers a way to hedge against fossil fuel price volatility.

The GreenChoice program was authorized by the Austin city council in 1999 and the program was launched in 2000. The initial rate was set at 1.7 cents per kilowatt hour. This rate did fully recover the costs of the original green power sources and was subsidized up to $1 million. Ten months after launching its program, Austin Energy had fully subscribed its initial 40 MW of new renewable supply and had to contract for additional renewable supply. Austin' second offering was not subsidized and was priced at 2.85 cents per kWh. This represented the contract price for the wind and did not include congestion or ancillary services costs, which were not anticipated. At the end of 2003, Austin Energy increased the green power rate to 3.3 cents per kilowatt hour. This new rate covered the wind contract price, congestion costs and ancillary services costs. The new rates applies to new program subscribers only; existing subscribers continued to pay the lower green power rates established in earlier phases of the program.

At the same time, standard fuel charge rates were changing as well. This made the difference between standard service and green pricing larger or smaller. The price difference between standard electric service and GreenChoice will fluctuate over time because of changes to the fossil fuel charge. Only GreenChoice customers get the benefit of ten years of price stability, and that level of price certainty is very attractive to customers, particularly large consumers of electricity. Currently the price of their renewable energy product is actually lower then the price of their default service, creating a "negative premium" for green power customers.

Case Study: Model Renewable Portfolio Standard

State:	New York
Eligible Technologies:	Photovoltaics, Landfill Gas, Wind, Biomass, Hydroelectric, Fuel Cells, Biogas, Liquid Biofuel, Tidal Energy, Wave Energy, Ocean Thermal
Applicable Sectors:	Investor-Owned Utilities
Standard:	25% by 2013 (1% of which is from voluntary market)
Date Enacted:	9/24/2005
Recovery of Costs:	Volumetric charge on customer's bills
Cost Cap:	No cap, but central procurement by NYSERDA prevents bids that are too costly
Penalties:	No penalty because of central procurement
RPS Administrator:	New York State Energy Research and Development Authority

On September 24, 2004, after a year and a half of public hearings and participation by over 150 parties, the New York State Public Service Commission (PSC) issued its "Order Approving Renewable Portfolio Standard Policy," which is the PSC's renewable energy policy and provided definitions and targets for carrying out the policy.

Shortly after the Order was issued, Congress authorized an extension until December 31, 2005 of the Production Tax Credit (PTC) allowable for certain renewable facilities. To take advantage of the credit, the PSC authorized, on December 16, 2004, a "Fast Track" procurement under the RPS to facilitate development of renewable resources that might be able to meet the December 31, 2005 deadline. As a result of that solicitation, 22 proposals were submitted by the January 18, 2005 deadline, and awards were given to seven projects. Those seven projects are to begin in 2006 to produce 821,000 MWH per year of renewable energy, which fills the majority of the Commission's first year goal for meeting the 25% target by 2013.

On April 14, 2005 the PSC approved the RPS Implementation Plan, which identifies the procedures for determining eligibility, establishing future procurements, and monitoring the program.

The RPS calls for an increase in renewable energy used in New York from its current level of about 19% to 25% by the year 2013. This increase is estimated to create 3,700 megawatts (MW) of new renewable generation by 2013. The PSC conservatively estimates that the RPS will decrease the emissions of major air pollutants; CO2 will be reduced by 7.42%. Along with the significant emission reductions that will improve the State's environment, the State will also see a boost in economic development activity from the growth of the renewable energy industry in the State.

The PSC identified two approaches to achieve the 25% goal:

1) A central procurement approach that would provide for increases to about 24%; and
2) A voluntary green market approach that would provide at least the other 1%.

The central procurement approach will consist of two tiers of eligible resources. A Main Tier consisting of medium-to-large-scale electric generation facilities, and a Customer-Sited Tier consisting of smaller, on-site – or "behind the meter" – technologies. Renewable resources currently eligible to participate in the Main Tier of the program include wind, hydroelectric, biomass, biogas, liquefied biofuel, and ocean or tidal power facilities. Eligible resources in the customer-sited tier include fuel cells, solar photovoltaic, and wind technologies.

The RPS legislation provides for the regulated investor-owned utilities to collect a surcharge on most delivery customer bills and transfer those funds to the New York State Energy Research and Development Authority (NYSERDA). The cost of the RPS program will be recovered as a separate volumetric charge on the customer's bill. Cost estimates for the program range from $580 – 750 million, offset by approximately $360 million in expected wholesale decreases.

For residential customers, over the life of the Program, cumulative bill impacts are forecast to range from a reduction of 0.9 percent to an increase of 1.68 percent; for commercial customer, estimated bill impacts range from a 0.78 percent reduction to a 1.79 percent increase; and for industrial customers, bill impacts could range from a reduction of 1.54 percent to an increase of 2.2 percent.

NYSERDA will administer the RPS program for the PSC. NYSERDA will enter into contracts to provide incentives, based on actual production, to renewable energy producers who either sell and deliver their energy into the New York wholesale market or will provide funding for customers to install such facilities "behind the meter". In return for these incentives, the energy producers will agree not to sell the environmental attributes of their renewable energy to any other entity during the terms of their agreements.

Monitoring and evaluation of the administration of the program will occur through year-end status reports that address aggregated quantities of RPS Program energy generated and payments associated with the environmental attributes of that energy for both the main and customer-sited tiers, as well as progress in meeting the RPS Program annual targets.

Unlike most other jurisdictions, there is no requirement on utilities to purchase renewable energy as part of their energy portfolio, but the affect of the incentives will be that more renewable energy will be sold by producers into the ISO-sponsored wholesale market and there will be further encouragement for the installation of renewable resources by customers on their side of the meters. These actions will in turn affect the percentage of renewable energy used in the State.

The PSC will review certain aspects of the Program in 2009, including costs and benefits, recommendations for modifications to the list of eligible resources, changes to the delivery requirement, and plans submitted by NYSERDA to transition the Program to a more market-based approach.

Case Study: Model Public Benefits Fund

State:	California
Eligible Technologies:	Solar Thermal Electric, Photovoltaics, Landfill Gas, Wind, Biomass, Geothermal Electric, Municipal Solid Waste, Anaerobic Digestion, Small Hydroelectric (less than 30 MW), Tidal Energy, Wave Energy, Ocean Thermal, Fuel Cells (Renewable Fuels)
Total Fund:	$135 million per year
Charge:	Varies by utility: $0.002/kWh - $0.003 kWh
Administrator:	California Energy Commission
Affected Utilities:	Pacific Gas and Electric Company (PG&E), Southern California Edison Company (SCE) and San Diego Gas and Electric Company (SDG&E)
Programs Funded:	1. Existing Renewable Facilities Program 2. New Renewables Program 3. Emerging Renewable Program 4. Consumer Education Program

In 1996, the California legislature created the Renewable Energy Program to foster the development of renewable electricity generation technologies and expand the renewable energy market in the state. To administer the program the Legislature authorized the collection of a public goods surcharge from Investor-Owned Utility (IOU) ratepayers from 1998 through 2001. The IOUs include Pacific Gas and Electric Company (PG&E), Southern California Edison Company (SCE) and San Diego Gas and Electric Company (SDG&E). The three IOUs were required to collect $540 million via the public goods surcharge. Voluntary contributions from other publicly-owned utilities or individuals were also allowed.

In September 2000, the legislature adopted the Reliable Electricity Service Investments Act (RESIA) as the result of Assembly Bill 995 and Senate Bill 1194. These two pieces of legislation mandated that the three investor-owned utilities collect $135 million annually for 10 years beginning in 2002 to support the Renewable Energy Program.

In September 2002, Senate Bill 1038 was signed into law. This bill directed the Energy Commission on how to implement the Renewable Energy Program from 2002 through 2006. The goal of SB 1038 was to establish a competitive, self-sustaining renewable energy supply for California while increasing the near-term quantity of renewable energy generated in the state.

Senate Bill 1038 changed the allocation of funds collected through the system benefits charge across the different program areas. Table 1(on the following page) shows the differences in allocation of funds between SB 90, enacted in 1998 and SB 1038, enacted in 2002.

Table 1: Comparison of the reallocation of funds between 1998 and 2002

Program	SB 90 (year 1998)		SB 1038 (year 2002)	
	Percent of Total	$ Million/Year	Percent of Total	$ Million/Year
Existing Renewable Facilities	45%	$60.75	20%	$27
New Renewables	30%	$40.5	51.5%	$69.53
Emerging Renewables	10%	$13.5	17.5%	$23.62
Customer Credit	14%	$18.9	10%	$13.5
Consumer Education	1%	$1.35	1%	$1.35
TOTAL	**100%**	**$135**	**100%**	**$135**

The California Energy Commission (CEC) administers the Renewable Energy Program and provides annual reports to the Legislature. Up until mid-2004, the CEC had provided quarterly reports to the Legislature.

The CEC manages the renewables funds through the following four programs:

(1) Existing Renewable Facilities Program – 20% ($27 million per year)
(2) New Renewables Program – 56% ($75.6 million per year)
(3) Emerging Renewable Program – 2% ($29.7 million per year)
(4) Consumer Education Program – 2% ($2.7 million per year)

In 2003, the CEC discontinued the Customer Credit program, which provided credits to consumers who purchased renewable energy from eligible energy providers, and reallocated the funds to the following programs: 90% to the Emerging Renewables Program and 10% to the Consumer Education Program.

The Existing Renewable Facilities Program (ERFP) supports the development and maintenance of existing renewable-energy projects (i.e., renewable projects that have already been constructed). This account uses a production-credit mechanism based on the kilowatt-hours generated by a project.

The New Renewables Program supports prospective new renewable-energy projects that generate electricity. These projects must be brought on line within five years, and like the existing technologies account, incentives are awarded based on the number of kilowatt-hours generated.

The Emerging Renewables Program is being administered through a rebate program. SB 1038 (2002) specifies that photovoltaics (PV), solar thermal electric, fuel-cells that use renewable fuels, and wind turbines up to 50 kW are eligible under this program. Rebate levels are reduced by $0.20 per watt every six months. Rebates are 15% less for owner-installed or self-installed systems, and 25% more for systems installed on affordable housing (not to exceed 75% of the system cost). Overall, 10% of the Emerging Renewables funds is allocated for rebates for performance-based systems of 30 kW or greater.

The Consumer Education Program provides funds to promote renewable energy and help build the market for emerging renewable technologies.

Funds available for a particular program element may be reallocated to another program element at the Commission's discretion. Any reallocation of funds should be consistent with the following requirements.

- The reallocation should be consistent with the Commission's regular reports;
- The reallocation may not increase the funds available to the Existing Renewable Facilities Program; and
- The reallocation may not decrease funds available to the New Renewable Facilities Program.

Interest earned on the funds deposited in the Renewable Resource Trust Fund may be used too augment funds for a particular program element at the Commission's discretion, as recommended by the Committee. Such interest may also be used for the Commission's administration of the Renewable Energy Program to the extent appropriated by the Legislature and authorized by the California Department of Finance. The Commission may also use funds deposited into the Renewable Resource Trust Fund pursuant to SB 1038 to administer the Renewable Energy Program.

Since the Renewable Energy Program began, the following has been accomplished:

- Brought more than 429 MW of new renewables capacity on-line with the potential for new projects to eventually total 1,200 MW of new renewable capacity for California's electric grid. The CEC expects additional new capacity to come on-line over the next several years as the RPS program matures.
- Helped 275 existing facilities remain operative for 4,400 MW of renewables capacity.
- Supported over 200,000 customer purchases of electricity generated by renewable energy before the suspension of direct access contracting options for electricity customers.
- Provided rebates to more than 9,700 customers for installing on-site renewable technology systems, representing over 39 MW of solar and wind capacity, with the potential for an additional 19 MW from 4,628 systems in various stages of development.
- Assisted Californians in making educated energy decisions by providing information to consumers and Renewable Energy Alliance members statewide about renewable energy and the state's incentive programs, and how to support renewables in today's marketplace.
- Continues to collaborate with the utilities and the CPUC in developing the rules for implementing the RPS and a system to track the utilities' progress and verify their compliance.

Case Study: Model Net Metering Rule

State:	New Jersey
Eligible Technologies:	All Class I Renewable Energy, including Solar Thermal Electric, Photovoltaics, Landfill Gas, Wind, Biomass, Hydroelectric, Geothermal Electric, Anaerobic Digestion, Tidal Energy, Wave Energy, Fuel Cells (Renewable Fuels)
Applicable Sectors:	Residential, Commercial
Limit on System Size:	2 Megawatts
Treatment of Net Excess:	Credited to following month, unused credit purchased at avoided cost at end of annualized period
Utilities Involved:	All
Interconnection Standards?	Yes
Date Enacted:	9/13/2004
Effective Date:	10/4/2004
Expiration Date:	1/9/2006

In 1999 the New Jersey legislature enacted the Electric Discount and Energy Competition Act (EDECA), which required utilities in New Jersey to offer net metering to residential and small commercial customers generating electricity with photovoltaic and wind systems. In September 2004, the New Jersey Board of Public Utilities enhanced the existing net metering policy. The 2004 policy expanded the number of customers that could use net metering, added provisions to simplify and expedite the process to connect systems to the New Jersey electric grid and expanded the eligible technologies to include all Class I renewable energy technologies. New Jersey's net metering policy has in part been responsible for a 550 percent, three-year growth in their solar energy market. Since 2001, 503 solar systems have been installed in New Jersey, representing a capacity of 4,593 kW. In the first half of 2005, 117 solar systems have been installed, representing a capacity of 918 kW.

The 2004 rules simplify the grid interconnection standard by clarifying the requirements and making the process more transparent and cost-effective. They also set strict deadlines for utilities to interconnect with distributed generators. The New Jersey standard provides for expedited processing, with fixed fees if the generator passes a set of conservative screening criteria. In addition, equipment costs are kept low by allowing pre-tested units certified as safe to be installed without unnecessary additional tests and redundant equipment.

Under the 2004 policies, there are three levels of interconnection:

- Level 1: applies to inverter based customer-generator facilities, which have a power rating of 10 kW or less;
- Level 2: applies to customer-generator facilities with a power rating of 2 MW or less and certified by a nationally-recognized testing and certification laboratory as meeting IEEE 1547 and UL 1741 for compliance for operation with an electric distribution system; and
- Level 3: applies to customer-generator facilities with a power rating of 2 MW or less, which do not qualify for either the Level 1 or Level 2 interconnection review procedures.

Utilities credit customer at the full retail rate for each kilowatt hour produced by a Class I renewable energy system installed on the customer-generator's side of the electric revenue meter, up to the total amount used by that customer during an annualized period. Excess power generated by customer systems is credited to the following month. At the end of an annualized period, unused credit is purchased at a rate equal to the supplier/provider's avoided cost of wholesale power.

In addition, the 2004 policy states that customers that are eligible for net metering own the renewable energy certificates from their generation. Customers may apply to the BPU to participate in NJ's Solar Renewable Energy Certificates (S-RECs) program, which provides a means for solar certificates to be created and a verified and allows the certificates to be sold to electric suppliers to meet their solar RPS requirement. The New Jersey RPS requires the construction of 300 MW of new Class I renewable energy technologies by 2008, and to provide at least 20 percent of new demand from renewables by 2020.