

DISTRIBUTED GENERATION

Finding a Sustainable Path Forward



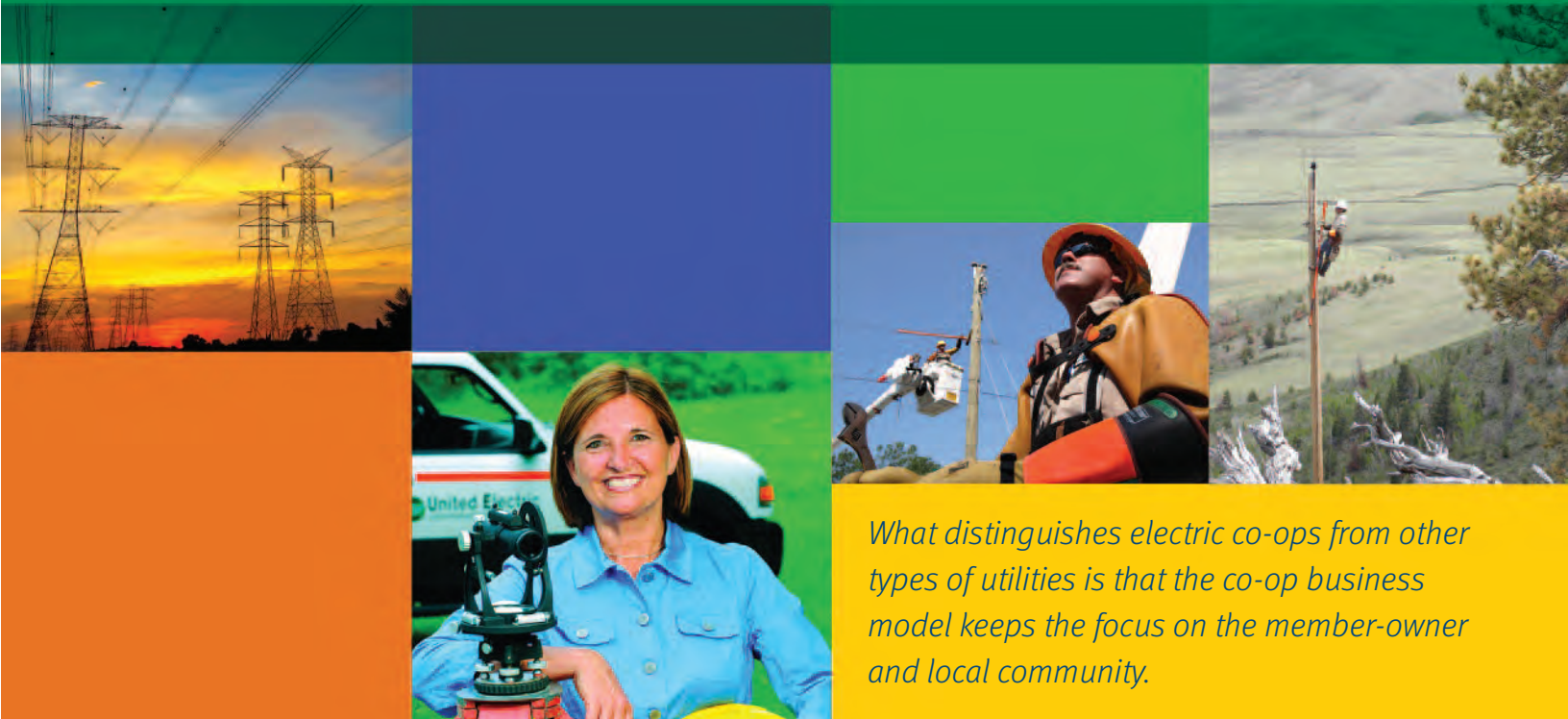
For additional information, contact:

Jay Morrison
Vice President, Regulatory Issues
(703) 907.5825 or jay.morrison@nreca.coop

Mary Ann Ralls
Associate Director, Regulatory Counsel
(703) 907.5837 or maryann.ralls@nreca.coop

ELECTRIC COOPERATIVES

America's Member-Owned Utilities



What distinguishes electric co-ops from other types of utilities is that the co-op business model keeps the focus on the member-owner and local community.

What is an electric cooperative?

Electric cooperatives are private, not-for-profit businesses governed by their consumers (known as “member-owners”). All co-ops, including electric co-ops, are democratically governed and operate at cost. Every member-owner can vote to choose local boards that oversee the co-op, and the co-op must, with few exceptions, return to member-owners revenue above what is needed for operation. Under this structure, electric co-ops provide economic benefits to their local communities rather than distant stockholders.

The majority of co-ops distribute electricity to consumers through low-voltage residential lines that cover over 75 percent of the nation’s land mass. Many of these “distribution co-ops” have joined to create co-ops that provide generation and transmission services (“G&T” co-ops). Distribution co-ops also buy power from investor-

owned utilities (IOUs), public power systems, federal hydropower Power Marketing Administrations (PMAs), and the Tennessee Valley Authority (TVA).

The dawn of rural electrification

In 1935, about 90 percent of the rural farms and communities in America had no electricity. The primary providers of electricity were IOUs, which saw little or no opportunity to profit from serving rural customers. To bring electricity to everyone, President Franklin D. Roosevelt created, by executive order, the Rural Electrification Administration (REA). When IOUs still would not provide service, farm communities across the country tapped financing from the REA and adopted the private co-op business model to deliver electricity in their communities.

Cooperatives in perspective

Today, 930 electric co-ops serve 42 million consumers in 47 states. Electric co-ops serve an average of 7 customers per mile, compared with 35 customers per mile served by IOUs and 47 customers per mile served by public power systems. Electric co-ops bring electricity to only 12 percent of the population, but maintain 42 percent of the nation's electricity distribution lines.

The cooperative difference

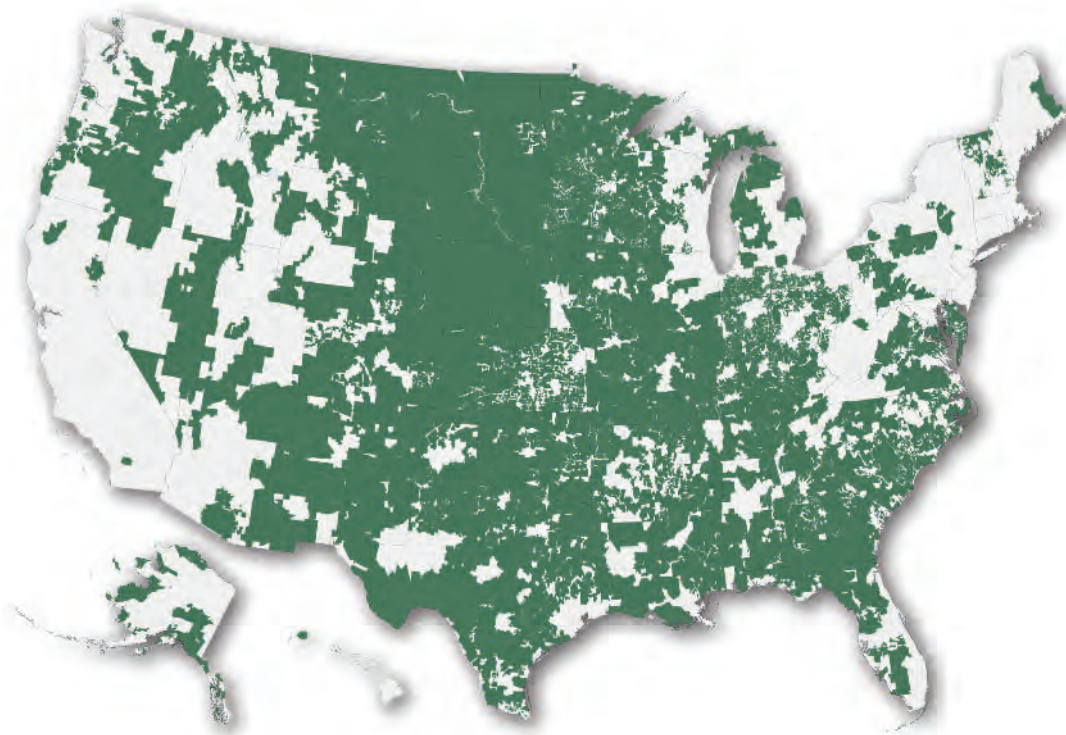
What distinguishes electric co-ops from other types of utilities is that the co-op business model keeps the focus on the member-owner and local community. Electric co-ops are involved in community development and revitalization projects, such as small business development and job creation, improvement of water and sewer systems, and assistance in health care and education services.

The future of electric cooperatives

The private, member-owned co-op business model has been a foundation for growth in many communities. To keep pace with this growth, electric co-ops, like all segments of the utility industry, must now plan for a significant amount of new generation capacity. The growing consumer base will continue to depend upon coal, nuclear, and gas generation, with a supporting role increasingly played by renewable energy resources and efficiency measures. As such, electric co-ops lead the way in developing new, cleaner coal plants along with alternatives to fossil fuels.

Renewable energy makes up almost 11% of the electricity provided by electric co-ops, with more than 340 megawatts from non-hydroelectric renewable generation owned by the co-ops themselves and more than 2,000 megawatts purchased from renewable developers. Almost 90 percent of the co-op industry offers their consumers power from renewable energy.

America's Electric Cooperatives





COOPERATIVES AND DISTRIBUTED GENERATION

What is distributed generation?

Distributed generation (“DG”) generally refers to non-centralized sources of electric generation, using resources such as wind, photovoltaic (PV), combined heat and power (CHP) and diesel, usually located at or near consumers’ homes or businesses. If developed properly, DG can potentially provide consumers and society with many benefits, including economic savings, improved environmental performance, and greater reliability.

Co-ops are actively investing in distributed generation

As part of their continuing efforts to find ways to lower costs for rural electric consumers, co-ops across the nation are pursuing carefully considered, cost-effective DG technologies that meet the needs of their consumers and support their systems. Currently:

2/3 of co-ops interconnect with member-owned generation

75% have interconnection policies, up from 45% in 2009

45% purchase excess power from member-owned generation, up from 20% in 2009

47% offer net metering, up from 28% in 2009*

A few examples of co-op DG efforts include:

SOLAR—United Power in Brighton, CO offers community solar to its members. The members receive a monthly bill credit for the value of their solar panels’ production, allowing them to own solar without having to install the panels directly on their homes.

WIND—Basin Electric Power Cooperative in Bismarck, ND purchases excess power from a 750-kW wind turbine, installed on the Rosebud Sioux Indian Reservation, adjacent to the Tribe’s casino/hotel complex in South Dakota.

COMBINED HEAT AND POWER—East Kentucky Power Cooperative in Winchester, KY purchases the excess power from a wood waste cogeneration facility owned by Cox Interior, Inc.

NRECA offers DG-related tools

NRECA’s research arm, the Cooperative Research Network (CRN), is working with member co-ops and the FREEDM Systems Center national laboratory at North Carolina State University to develop a “plug and play” PV system. Supported by a grant from the Department of Energy (DOE), the project focuses on streamlining permitting, inspection, and interconnection to make systems consumer-friendly and cost-effective, while still meeting reliability and safety requirements.

CRN and several partners also have signed a cooperative agreement with DOE for a multi-state, 23 MW, utility-scale solar installation research project that will explore how standardization can help bring down the “soft” costs—labor, procurement, supply chain and other costs—of PV installations, while also reducing uncertainty about the effects of these installations on a system.



*According to internal NRECA surveys

To aid member co-ops considering DG programs, NRECA also offers a wide variety of web-based resources, such as the Distributed Generation Toolkit (which includes a business and contract guide for DG interconnection, model interconnection applications, short- and long-term interconnection contracts, a DG manual and white paper) and papers on net metering and feed-in tariffs. **These resources can be found at www.nreca.coop/nreca-on-the-issues/energy-operations/distributed-generation/dg-toolkit.**

Benefits of distributed generation

In certain applications, DG technologies can provide consumers, co-ops, and society significant benefits, including reduced transmission and distribution costs, reduced emissions, and enhanced reliability.

For instance, generation located near demand can reduce energy losses and may allow utilities to

defer upgrades to substations and transmission and distribution facilities.

Meanwhile, some technologies, including micro-turbines and internal combustion engines, can offer increased efficiency by taking advantage of waste

heat, while those powered by renewable resources can have emissions and land-use impact advantages over central station generation.

Possible pitfalls of distributed generation

Many of the presumed benefits of DG are highly dependent on the manner in which facilities are owned, planned, installed, and operated. Policies that encourage DG without taking these factors into account, or which do not provide the flexibility necessary for utilities and consumers to craft business models that work for them, will be extremely costly, without capturing any of the presumed benefits.

Risky policies are ones that:

Limit the ability of utilities to participate in DG as a part of their business, for example, prohibiting utilities from selling or leasing DG technologies to consumers;

Promote DG at the expense of non-DG consumers, such as mandated net metering, feed-in tariffs or value of solar (VOS) tariffs;

Fail to recognize that high penetrations of DG can increase rather than decrease utility system costs;

Fail to ensure that DG consumers pay their fair share of the costs of the utility system;

Undermine state utility territorial laws by authorizing DG vendors to sell power at retail from consumer-sited DG; and

Fail to take into account the impact of different technologies and different applications on each individual distribution system.

Flexibility is essential in realizing the potential benefits of distributed generation while avoiding prospective pitfalls.

For these reasons, decision makers should be careful not to require utilities, consumers or taxpayers to financially support expensive capital investments or subsidies to support DG applications where benefits may not ultimately outweigh costs.

The keys to successful DG

Cost-effective distributed generation technologies have the ability to bring significant benefits to co-ops and their member-owners. These benefits, however, cannot be taken for granted. Flexibility—in selecting the right DG technologies and projects, and in structuring arrangements that meet the needs of individual utilities and consumers—is essential in realizing the potential benefits of distributed generation while avoiding prospective pitfalls. Non-profit cooperatives have a vested interest in finding ways to balance the needs of their member-owners with maintaining system reliability.



COOPERATIVES AND SOLAR POWER



Renewables programs in the sun

The nation's member-owned electric cooperatives are pursuing the development and utilization of cost-effective solar distributed generation throughout the country. According to recent NRECA data and the Solar Electric Power Association's "2012 SEPA Utility Solar Rankings," co-ops located in 18 states have more than 4,000 solar-powered consumer-owned residential DG projects, representing more than 23 megawatts (MW) of capacity. The addition of 700-plus commercial and industrial (C&I) projects brings co-ops' solar-powered DG capacity to almost 53 MW. Cooperatives also are investing in solar projects, using business models selected to best serve their member-owners through least-cost options.

Solar success stories

KAUA'I ISLAND UTILITY COOPERATIVE, LIHUE, HAWAII.

KIUC, which is regulated by the Hawaii Public Utilities Commission, has 928 residential projects, with 3.707 MW of capacity. The addition of 84 C&I projects with 4.345 MW of capacity brings the Hawaii co-op's total to 1,012 projects with 8.052 MW of capacity.

KIUC has a long history of using solar energy—both utility-scale and residential—to reduce its consumption of fossil fuels continues to evolve as technology becomes cost effective. The co-op also purchases 6 MW from a 6 MW solar array and anticipates adding more solar to the system in 2014. However, KIUC emphasizes the need for consumers to understand their options and obligations before making what can be a large, long-term investment, which include HPUC-required interconnection procedures to ensure that the PV system can be safely and reliably tied into the utility grid and applicable net metering rules.

SULPHUR SPRINGS VALLEY ELECTRIC COOPERATIVE, WILLCOX, ARIZONA.

SSVEC has 640 residential projects, with 1.906 MW of capacity. The addition of 249 C&I projects with 1.861 MW of capacity brings the Arizona co-op's total to 889 projects with 3.767 MW of capacity.

The SunWatts Incentive Program, which is funded through an Arizona Corporation Commission-mandated surcharge on electric bills, gives SSVEC members access to solar power generation through either a one-time incentive or one based on performance. Under the one-time variant, for rooftop systems of 10 kilowatts or less, the co-op will pay a single incentive per watt, up to 35 percent of the system cost, subject to the availability of funds and the applicant's place on the reservation list. Under the performance-based incentive, members collect funds based upon their PV system's production of kilowatt-hours (kWh). This incentive varies, depending on the length of the incentive agreement.

For PV systems over 10 kW or that cost more than \$75,000, members can no longer collect a one-time incentive, but remain eligible for the performance-based program. Systems above 50 kW are not eligible for incentives, nor are systems that exceed a member's connected load by more than 25 percent. Limits for C&I meters are higher.

Co-ops located in 18 states have more than 4,000 solar-powered consumer-owned residential DG projects, representing more than 23 megawatts (MW) of capacity

The incentive program currently is fully subscribed, and the co-op is now collecting incentive reservation forms from members. SSVEC has also installed over 40 PV facilities at schools within its service territory.

SOUTHERN MARYLAND ELECTRIC COOPERATIVE, HUGHESVILLE, MARYLAND. SMECO has 224 residential projects, with approximately 2.5 MW of capacity. The addition of 33 C&I projects with 3.2 MW of capacity brings its total to 329 projects with approximately 5.7 MW of capacity. The co-op, which is regulated by the Maryland Public Service Commission, provides bill credits to system owners under the MDPSC's net metering regulations.

Additionally, SMECO developed a 5.5 MW solar system project, commissioned in late 2012, which will help the co-op meet its obligations under Maryland's Renewable Portfolio Standards. SMECO currently is considering additional solar opportunities.

LA PLATA ELECTRIC ASSOCIATION, DURANGO, COLORADO. LPEA 337 residential projects, with 1.170 MW of capacity. The addition of 45 C&I projects with 0.327 MW of capacity brings the Colorado co-op's total to 382 projects with 1.497 MW of capacity.

The Colorado co-op encourages distributed renewable energy projects, and now has more than 375 PV and wind generators interconnected with its electric distribution system. LPEA's net metering program is available to residential and commercial members on a first-come, first-served basis until the rated generating capacity owned

and operated by members in LPEA's service territory reaches 1 percent of the co-op's aggregate peak demand. The excess generation is carried over for a twelve-month period ending in April; at that point, the member is credited at LPEA's average wholesale cost. The net metering program values member generation at a fair rate and helps to ensure a safe installation.

The co-op offers an optional Renewable Energy Credit (REC) contract and REC payment for residential or commercial, grid-tied solar PV installations located within its service territory.

OKANOGAN COUNTY ELECTRIC COOPERATIVE, WINTHROP, WASHINGTON. OCEC has a cooperative-owned and a member-owned community solar project on its system. OCEC launched the first project, which it owns, in 2010. Totaling 20.3kW and eligible for Washington State production tax credits, it was fully subscribed within a few weeks. Under the agreement which runs through June 2020, OCEC pays the member-investors for the kWh produced at the preceding year's average wholesale rate.

Even though many OCEC members were interested in participating in community solar, the state's incentive program limited annual production payments for utility-owned projects, which capped the size of utility projects. However, the state program does not limit incentives for non-utility projects, so a local non-profit organized a second community solar project with Winthrop as the host. The Winthrop project, which has an installed capacity of 22.8kW, became operational in June 2011.





COOPERATIVES ON NET METERING

What is net metering?

Net metering is one of many techniques available to measure and value the output of customer-owned generation. Net metering rules generally provide that consumers with certain self-generation capabilities should have a meter that rolls forwards when the customer consumes power from the grid and rolls backwards when the customer exports power to the grid, thus compensating the consumer at the retail rate for its generation. If the consumer uses more energy over the course of a billing period than it has generated, it pays only for the net energy imported from the system, plus any fixed monthly charges provided by the rate schedule.



Source: Environmental Protection Agency

Net metering varies by state

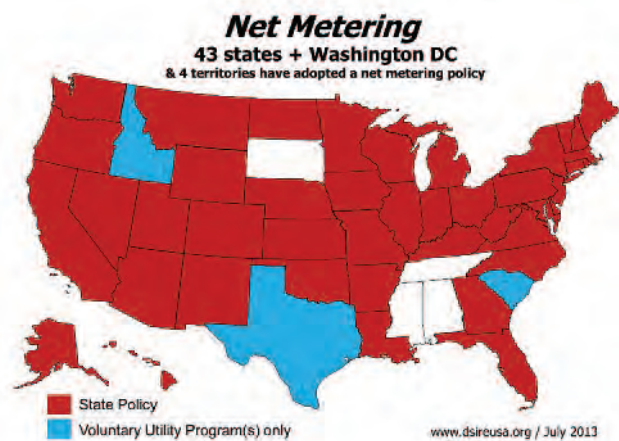
43 states have adopted net metering, but each state handles it very differently. When a consumer generates more than they have used over the course of a billing period, certain states prohibit any payment to consumers for net exports. Other states require net credits to be rolled over to the next month, generally up to one year and some states require utilities to pay consumers “avoided cost” (like with PURPA) for net exports at the end of a billing period or at the end of a year. Customer generators with net excess generation may still pay fixed monthly charges provided by the rate schedule for all customers in the same rate class.

The range of eligible units and number of consumers within state programs vary widely. Many states, like Alaska and Indiana, limit net metering to only renewable technologies. Others include qualifying facilities under PURPA. Most states have size limits on the units that qualify for net metering.

Kentucky and Wyoming limit qualifying units to no larger than 30 kW and 25 kW, respectively, while New Mexico’s size limit is 80 MW and Ohio has no size

limit. Some states have also imposed a limit on the total number of consumers, or total capacity of consumer-owned generation, for which any utility has to provide net metering service. Louisiana and Michigan limit net metering to 0.5% and 0.75% of the utility’s historic peak load, respectively.

Net meters allow customers to under-pay the fixed costs they impose on the system.



Why do so many states have net metering rules?

Many states adopted net metering in the early 1980s as a way of implementing PURPA Section 210’s requirement that utilities buy the output of qualifying small power production facilities. Other states adopted net metering because it provides a simple, easily-administered way of compensating consumers for their generation. Still others have adopted net metering to subsidize the use of environmentally-friendly renewable technologies.

Why are utilities concerned about net metering?

Net metering policies require utilities to pay consumers the retail price for wholesale power. The retail rate utilities charge includes not only the marginal cost of power, but also recovers costs incurred by utilities for transmission, distribution, generating capacity, and other utility services not provided by the customer-generator.

The policies require utilities to pay high costs for what is often intermittent, low-value power that cannot be scheduled or dispatched reliably to meet system requirements. Customer generation that could technically be dispatched to meet requirements are not required to enter into operating agreements with utilities in order to obtain net metering.

Net meters allow customers to under-pay the fixed costs they impose on the system. A utility has to install sufficient facilities to meet the peak requirement of the consumer and recover the costs of those facilities through a kWh charge. When the net meter rolls backwards, it understates the total energy used by the consumer, and thus understates the consumer's impact on the fixed costs of the system. It also understates the consumer's total share of other fixed charges borne by all consumers such as taxes, stranded costs, transition costs, and public benefits charges.

Net meters can also be deliberately or inadvertently gamed. Consumers can take power from the system at peak times when it costs the utility the most to provide it, and then roll their meters backwards by generating power at non-peak times when the utility has little need for it. That is a particular risk, for example, with gas and diesel fueled units that can be operated on demand.

Different kinds of net metering

AGGREGATED NET METERING (ANM) allows one customer who owns a generating asset and receives service via multiple meters or accounts on the same or contiguous property to aggregate or combine loads so that the generator can offset utility purchases for the aggregated load.

COMMUNITY NET METERING (CNM) allows multiple customers of the same utility to share the output of a generating asset that does not have to be on their properties, and to offset utility power purchases with each customer's pro rata share of the generator's output.

VIRTUAL NET METERING (VNM) allows customers to combine loads from multiple meters that they own, located at different facilities on different properties.

Like single customer/one meter net metering, ANM, CNM and VNM programs can result in unfair cost shifting among customers. Also, because ANM, CNM and VNM programs involve more meters and, oftentimes, larger generation units, economic and reliability issues noted below can be compounded. Allocating excess kWh credits can be complicated, and can impose additional IT and billing system costs on the utility. Credit allocation may also be subject to gaming if the accounts have different rates.

How can we gain the benefits of net metering without unfair cost shifting?

ADOPT POLICIES THAT SUPPORT RENEWABLE TECHNOLOGIES WITHOUT SHIFTING COSTS BETWEEN CONSUMERS:

- Provide tax credits for consumers that install renewable generation;
- Appropriate funds for research, development, and demonstration projects aimed at lowering the costs of DG;
- Implement net billing programs. Such programs typically:
 - Permit interconnection of customer generation to the grid;
 - Permit consumers to use their generation to reduce their consumption of utility power;
 - Ensure appropriate compensation to consumers for their net excess generation at reasonable rates;
 - Ensure consumer generators pay an appropriate share of system costs, protecting other consumers from cross-subsidies.

IF NET METERING POLICIES ARE ADOPTED, IMPOSE APPROPRIATE LIMITS:

- They should apply only to small residential generators (<10 kW) that use intermittent renewable energy such as wind, solar, and hydro;
- They should only be permitted up to a small percentage (i.e., 0.1%) of the utility's historic peak load;
- They should not be available to:
 - larger, more sophisticated consumers who do not need the leg up;
 - larger units or large numbers of units, which can exacerbate the cost shifting problem; or,
 - gas or diesel powered units that can more easily be used to game net metering rules.
- They should be available only to consumers on marginal cost time-of-use rates that ensure that excess generation is credited at the appropriate value.
- They should be reviewed regularly to ensure that they are still necessary to meet the goals for which they were adopted and are not forcing other consumers to subsidize net-metered consumer costs.

FEDERAL RULES, IF ANY, SHOULD NOT PREEMPT STATE NET METERING RULES, INCLUDING THOSE THAT PUT LIMITATIONS ON THE AVAILABILITY OF NET METERING.



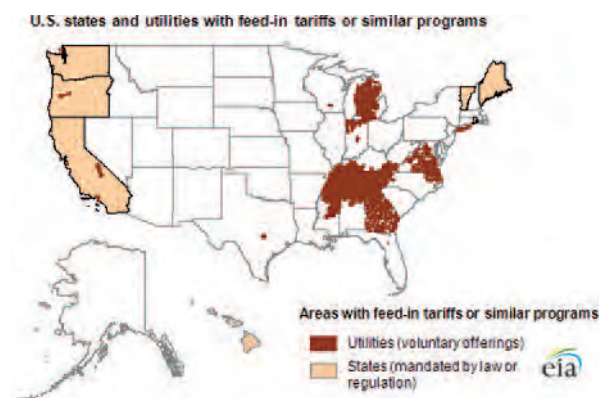
COOPERATIVES ON FEED-IN TARIFFS

What are feed-in tariffs?

Feed-in tariffs, also called “renewable energy payments,” are a policy tool used to promote renewable resources. They generally require utilities to sign long-term wholesale contracts with renewable energy generators agreeing to purchase power at rates established by state regulators, and at levels required to ensure generators a rate of return sufficient to attract investment.

The rates can be described as incorporating the societal benefits of renewable resources in addition to the energy and capacity value of the power. As an example, one program would pay wind projects between \$.12 and \$.18/kWh, and photovoltaic projects between \$.15 and \$1.08/kWh, depending on the underlying project.

Some feed-in tariff proposals provide for some generator or tax-payer funding for the costs utilities incur in complying with the feed-in tariff obligations. Feed-in tariffs may also be accompanied by other policies that grant renewable resources priority access to transmission capacity and grant renewable resources priority rights to be dispatched.



Source: U.S. Energy Information Administration (EIA), 2013

Why are advocates promoting feed-in tariffs?

Advocates claim feed-in tariffs will:

Facilitate investment in renewable generation by giving renewable energy generators a guaranteed, long-term wholesale purchaser at a favorable rate.

Promote less economic forms of renewable resources, such as community-sized wind projects, that advocates argue will provide greater societal benefits than the utility-scale projects.

Result in a whole range of potential benefits that can come from renewable energy development, including domestic “green jobs” and reductions in CO₂ and other power-plant emissions.

Why are utilities concerned about feed-in tariffs?

Utilities are concerned that feed-in tariffs will:

Raise the cost of power for retail consumers by requiring utilities to pay far more for certain favored resources than their “avoided cost” — the cost the utilities would incur to purchase the power elsewhere. For example, a feed-in tariff could require a utility to purchase wind from a back-yard wind generator at 23 cents/kWh at an hour when the utility could otherwise have acquired power from an existing coal or hydro resource for 2 cents/kWh.

Require utilities to purchase each category of renewable resource at a price that makes that category viable, instead of allowing the utility to acquire the lowest cost renewable available. For example, a feed-in tariff could require a utility to purchase solar energy at \$1.08/kWh when the utility could instead have acquired power from a utility-scale wind farm with equivalent environmental attributes for 12 cents/kWh.

Discourage developers from considering transmission capacity or utility resource planning when they site renewable generation due to lack of incentive, which is not cost-effective for consumers and may not provide adequate system reliability.

Require utilities to purchase far more generation than they need and possibly incur costs for:

- Upgrading the local distribution or transmission system to integrate the generation reliably or wheel the power to other wholesale purchasers;
- Selling the power into a market already saturated with renewables;
- Congestion charges associated with wheeling the power across an under-built transmission system; and
- Acquiring the reserves, ramping resources, reactive power resources, and other dispatchable generation required to integrate high levels of variable generation reliably.

A cooperative example

Big Flat Electric Cooperative serves about 1,069 consumers spread across more than 8,600 square miles of windy territory in north-central Montana. Even one community wind farm would far outstrip both the co-op's 5 MW peak demand and the capacity of the regional transmission system.

If there were a feed-in tariff, the co-op would have to replace its low-cost hydro power with high-cost wind energy and pay for:

Upgrades for transmission to integrate the wind into its own system;

Upgrades to the regional transmission system to move the power across three or more states to the nearest large population center;

Ancillary services required to support that transmission service.

The co-op would then lose money on every kWh of high-priced power it had to resell into the market. The economic impact on the co-op's 1,069 rural consumers would be devastating.

Policies associated with feed-in tariffs that give renewable resources priority access to transmission facilities would further increase costs to consumers by displacing the low-cost energy those facilities had been carrying to consumers and forcing consumers either to acquire higher cost resources over those transmission paths that are still available or pay to build new transmission capacity to replace that taken by the priority renewable resources.

Policies intended to reduce the cost of feed-in tariffs for utility consumers, such as a tax-based reimbursement fund, are unlikely to cover the full direct financial cost of the feed-in tariff and will not address the indirect operational, reliability, and cost challenges caused by feed-in tariffs.

How do feed-in tariffs differ from PURPA § 210, net metering?

Both feed-in tariffs and PURPA § 210 require utilities to interconnect with and to enter into long-term wholesale contracts for the output of renewable resources. PURPA, however, included several consumer protections not available under feed-in tariff policies. Both feed-in tariffs and net metering are designed to require utilities to interconnect with and purchase the output from certain generators at a rate that exceeds most utilities' avoided cost. Net metering laws, however, generally may include some limits not imposed by feed-in tariffs.

PURPA	NET METERING	FIT
Price to utility is capped at avoided cost and drops to 0 when utility has met its load needs	Compensate net metering (NM) generation at retail rate which results in unfair cross-subsidization of NM consumers' costs by others	Price includes incentive to support the underlying eligible generation resource, regardless of utility need for power, which is almost always higher than retail rate
Size is capped at 80 MW	Most states have limits on generator size or overall capacity w/in a program, which can limit other non-NM consumers' exposure to higher costs.	May not include a size limit
Utilities may request waiver from "must purchase" if a competitive wholesale market for the power exists		No utility waiver opportunity
Utilities can charge QF for providing interconnection and other services		May prohibit utility from charging for interconnection

Are feed-in tariffs consistent with federal law?

Since feed-in tariffs require utilities to purchase power at wholesale, the rates, terms, and conditions of wholesale sales of electricity are subject to one of two federal laws:

If the generator is a Qualifying Facility (QF) the rates at which it may sell at wholesale are subject to PURPA and are capped at the utility's avoided cost.

- In October 2010, the Federal Energy Regulatory Commission (FERC) clarified that states with renewable portfolio standards (RPS) may require utilities which must comply with the RPS to apply a multi-tier avoided cost calculation. Under such a calculation, utilities could only base avoided costs paid under a feed-in tariff on generation sources that would be eligible to meet the RPS in the same way as the generator seeking to sell under the feed-in tariff. However, this calculation would only apply if the state has a RPS and the purchasing utility needs the output from the generator seeking to sell under the feed-in-tariff to meet its RPS requirements.

If the generator is not a QF, its sale of wholesale power in interstate commerce makes it a public utility subject to regulation by FERC pursuant to the Federal Power Act (FPA).

- The FPA requires FERC to ensure that the rates, terms, and conditions of wholesale sales are just and reasonable and not unduly discriminatory or preferential.
- The FPA preempts any state effort to regulate rates for wholesale sales by public utilities.

How can we gain the benefits of renewable resources without the disadvantages of feed-in tariffs?

Adopt policies that support renewable technologies without shifting costs between consumers:

- Provide tax credits and other government funding for consumers that install renewable generation;
- Support expansion of the transmission grid to move renewable resources from the remote areas where they are most plentiful to population centers;
- Appropriate funds for research, development, and demonstration projects aimed at lowering the costs of DG; and,
- Remove federal regulatory burdens on consumers who generate their own power.

Implement net billing programs for small renewable generators. Such programs typically:

- Permit interconnection of customer generation to the grid;
- Permit consumers to use their generation to reduce their consumption of utility power;
- Ensure appropriate compensation to consumers for their net excess generation at reasonable rates;
- Ensure consumer generators pay an appropriate share of system costs, protecting other consumers from cross-subsidies.

Adopt policies that support renewable technologies without shifting costs between consumers



COOPERATIVES ON VALUE OF SOLAR (VOS) TARIFFS

Value of solar tariffs

Value of solar (VOS) is a proposed technique to measure and value the output of customer-owned solar distributed generation (“distributed PV”) to a utility. It’s been implemented by a few states and municipalities as an alternative to net metering. Whereas net metering requires utilities to compensate consumers at the retail rate for wholesale power that they generate, under a VOS tariff, all of the electricity consumed by the distributed PV customer is billed at the standard retail rate. A separate meter measures the energy produced by the distributed PV. The “full value” of that energy is calculated under the VOS tariff which the utility then credits to the customer’s monthly bill.

The proposed VOS technique calculates the full value based on “Value Buckets.” According to proponents, these would include, among other things:

ENERGY - The time-specific energy cost the utility avoids buying from the solar unit instead of the marginal unit from which it would otherwise obtain energy at that time.

GENERATION CAPACITY - Solar production correlates, in part, with utility system peaks. This may result in some level of generation capacity deferral (depending upon the capacity VOS and the utility’s forecast need for new generation).

TRANSMISSION & DISTRIBUTION (T&D) - Distributed PV may have the potential to defer some T&D expenses, due to the proximity of the distributed PV to load.

SYSTEM LOSSES - Distributed PV is sited at the load; therefore, losses associated with transmitting the energy across the T&D system may be avoided.

ENVIRONMENTAL BENEFITS - Distributed PV may reduce the environmental emission compliance costs utilities may face (e.g., SO_x and NO_x). In some jurisdictions, increased levels of distributed PV may lower the otherwise applicable renewable portfolio standard (RPS) requirements, potentially saving utilities compliance costs.

SYSTEM INTEGRATION - There are costs allocated to intermittent resources for additional operating reserves that are required to maintain system reliability.

Value Buckets are not limited to capturing actual cost savings to the utility and its consumers. They are designed to give the distributed PV customer additional compensation for future benefits that may not occur or may be inflated in value.

Why are advocates promoting VOS tariffs?

Under VOS tariffs, utilities would be required to pay distributed PV consumers or retail solar installers under long-term agreements at rates that reflect all of the potential benefits that distributed PV may possibly offer in the future to the utility, the electric grid, community and the environment as a whole, creating a strong market for investments in distributed PV.

Moreover, advocates assert, VOS tariffs promote consumer distributed PV that provides greater societal benefits than the utility-scale solar projects that are more cost-effective and have the same environmental attributes.

Advocates also argue that only VOS tariffs recognize the true value that a consumer offers the utility system and are thus necessary to ensure rate fairness.



Why are utilities concerned about the VOS tariffs?

Similar to feed-in tariffs, VOS tariffs can raise the cost of power for other retail consumers by requiring utilities to pay far more for resources than their avoided cost — the cost utilities would incur to purchase the power elsewhere. A VOS tariff could require a utility to purchase distributed PV at premium rates when the utility could otherwise have acquired power from an existing hydro resource or from a utility scale wind farm with equivalent environmental attributes at a significantly lower price.

VOS tariffs are supposed to reflect the value PV offers to the grid, communities, and the environment; however, depending on how the calculation is done, these benefits can be easily inflated and the costs imposed on the system by the technology ignored. For example, proponents of VOS tariffs presume that distributed PV will help utilities defer or avoid investments in distribution, transmission, or new generation capacity. In fact, if VOS tariffs encourage significant investment in PV, the utility could actually bear higher costs for:

- Upgrading the local distribution or transmission system to integrate the generation reliably. For example, at higher levels of PV, utilities will need to upgrade transformers, replace isolation devices to permit two-way flows on the distribution system, invest in distribution SCADA to permit the system to respond to greater uncertainty and variability in distribution loads and power flows, and install new communications networks in order to track and control smart inverters on the PV systems.
- Acquiring the reserves, ramping resources, reactive power resources, and other dispatchable generation required to integrate high levels of variable generation reliably. At higher levels of PV, the system can experience dramatic upramps during evening peak periods as solar generation tapers off at the same time that customers come home, turn on the air conditioning, turn on stoves, and begin to use hot water. Existing generation resources in some regions may not be able to meet those ramps and would have to be replaced.

VOS tariffs could also drive up electricity costs for consumers by charging utilities — and thus their customers — for many values not presently incorporated in electricity rates. Utilities charge consumers for the cost of providing safe, reliable, and affordable power. They do not charge consumers for all of the benefits that consumers and the economy get from that power. Nor do utilities charge consumers the value that their other generation resources offer consumers, communities, and the environment. Utilities, for example, do not charge consumers more than their cost for nuclear power because it has no air emissions. Utilities do not charge consumers more than their cost for utility-scale solar power because it produces no pollutants. Utilities do not charge more than their cost for coal-power to reflect the number of good jobs the coal mine and the coal plant provide the community. The VOS tariff requires the utility to tax some of its consumers with such costs in order to subsidize others.



How do VOS transactions differ from feed-in tariffs and net metering?

Both feed-in tariffs and net metering are designed to require utilities to interconnect with and purchase the output from certain generators at a rate that exceeds most utilities' avoided cost. Net metering laws, however, generally include several limits not necessarily imposed by feed-in tariffs or VOS tariffs.

Net metering rules require utilities to give consumers credit against their energy usage for energy their generators export to the system over the course of a billing period or longer period. This effectively compensates consumers at the retail rate for their generation up to the point where the generation completely offsets usage during the credit period. Some states credit any net excess generation to the utility or require payment at avoided cost. Feed-in tariffs require payment for all generation at the level required to provide the investor a rate of return designed to encourage the underlying generation resource. While feed-in tariffs are almost always going to be higher than the payment under net metering, VOS tariffs likely will require even higher payments than either net metering or feed-in tariffs as the price to be paid is not limited by either the utility's retail rate or the generator's revenue requirement. Depending on what is included in the "value buckets" and how those are calculated, the VOS tariff could provide investors a significant premium over their revenue requirement.

Most states limit the number of generators or amount of generation capacity entitled to net metering. The limits reduce non-solar consumers' maximum exposure to higher power costs needed to subsidize the solar consumer. Feed-in tariffs and VOS tariffs may not impose such limits, requiring other consumers to subsidize even large numbers of projects producing significant amounts of energy, even if that exceeds the total demands of the purchasing utility.

How can we gain the benefits of renewable resources without the disadvantages of VOS tariffs?

Adopt policies that support renewable technologies without shifting costs between consumers:

- Provide tax credits and other government funding for consumers that install renewable generation;
- Appropriate funds for research, development, and demonstration projects aimed at lowering the costs of DG.

Implement net billing programs for small renewable generators. Such programs typically:

- Permit interconnection of customer generation to the grid;
- Permit consumers to use their generation to reduce their consumption of utility power;
- Ensure appropriate compensation to consumers for their net excess generation at reasonable rates; and
- Ensure consumer generators pay an appropriate share of system costs, protecting other consumers from cross-subsidies.

Depending on what is included in the "value buckets" and how those are calculated, the VOS tariff could provide investors a significant premium over their revenue requirement.



DISTRIBUTED GENERATION: EXPLORING RETAIL RATES

Designing retail rates to accommodate distributed generation

Electric cooperatives are member-owned, member-governed, not-for-profit electric utilities. They exist to provide safe, reliable, and affordable electric service to the electric consumers that own them at rates that reflect the cost of providing that service. Like other utilities, cooperatives have traditionally designed their retail rates to recover their costs, to minimize cost shifting between or within rate classes, and to be simple and understandable.

As distributed generation is becoming more common, however, some co-ops are finding that their traditional rate designs may no longer meet their needs. Changes are needed to ensure those co-ops can recover their costs of service, minimize cost shifting between members, and provide members with accurate price signals for investments in distributed generation.

Traditional electric rates may not permit cooperatives to recover fixed costs as DG increases

Electric rates, particularly for residential customers, are typically comprised of a fixed charge, often referred to as the customer charge, and a variable energy charge, which is imposed on each kilowatt-hour (kWh) consumed.

For most utilities, including cooperatives, the customer charge is often considerably less than the actual fixed costs incurred to serve customers on the system. A large proportion of these fixed costs, which cooperatives incur in order to build the generation, transmission, distribution, communications, and other infrastructure required to ensure reliable electric service, are often recovered through the variable kWh energy charge.

The kWh charge is typically set at a level that is calculated to recover all of the cooperatives' fixed and variable costs each year based on its projected sales.

If members generate their own energy such that sales decrease below the levels anticipated when rates were set, the cooperative will not recover its full cost of providing service until it is able to institute a rate increase.

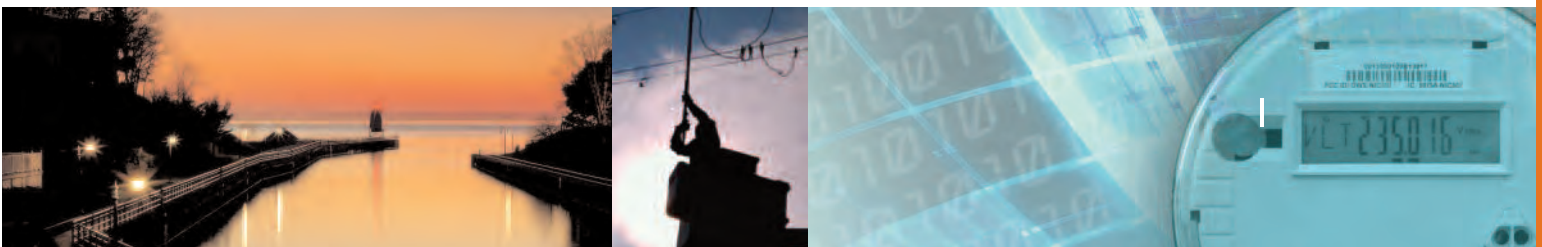
Traditional electric rates may shift costs from customers with DG to all other customers

Just as the cooperative's kWh charges are typically set to recover its full revenue requirement, they are also set at a level anticipated to recover a fair share of the cooperative's fixed costs from each member, based on average usage within each rate class.

If a subset of members install generation, and thus use significantly less than average, that group of members will not contribute their fair share of the cooperatives' fixed costs, shifting those costs to other members who are not self-generating.

The cost shifts will become more pronounced if cooperatives are forced to raise their kWh rates in order to recover their full revenue requirements. As DG penetration levels increase, this could lead to power becoming unaffordable for lower-income consumers.

The financial risk associated with declining kWh sales can be mitigated under a rate design that recovers costs in the same ways they are incurred by the utility.



While there are many rate options, rate designs that recover all of a cooperative's fixed costs with fixed charges can provide stability and rate equity

The financial risk associated with declining kWh sales can be mitigated under a rate design that recovers costs in the same ways they are incurred by the utility. Under this approach, fixed costs are recovered through fixed charges and variable costs through variable charges. This rate design, sometimes referred to as straight fixed variable rates, can be established by first conducting a cost-of-service study that identifies the utility's cost structure. Based on the study's results, the utility's retail rates are then rebalanced, through increases in the customer charge and decreases in the kWh charge.

Rebalancing rates in this manner serves to protect the financial stability of the utility that faces declines in kWh sales due to distributed generation. All cooperative members, including members who have installed distributed generation, pay a monthly customer charge that reflects the utility's fixed investment made on their behalf.

Rebalancing rates in this manner also eliminates the cross subsidies caused by the interaction between traditional rate designs and DG. Every member, regardless of whether they install DG, pays the cost of investments the cooperative makes in infrastructure required to serve that member. Other members without DG, therefore, are not required to pick up an inequitable share of the cooperative's costs.

Rebalancing rates to recover costs in the way they are incurred provides members more accurate price signals

Basic principles of rate design suggest that rates should send accurate price signals to consumers in order to encourage consumers to make good economic decisions.

Traditional rate designs, which incorporate some unavoidable fixed costs of service in the kWh rate, give members an inaccurate price signal, encouraging them to overinvest in DG so long as the cost to them is less than the fully loaded retail rate.

Rate designs that recover costs in the way they are incurred, on the other hand, provide a more accurate price signal. While any member could still invest in DG, they only have an economic incentive to do so if the variable cost of their own generation is less than the variable cost of the power the cooperative would have otherwise provided.

Some energy efficiency (EE) and DG proponents are concerned that rate designs with higher fixed costs and lower per kWh charges provide a reduced incentive to consumers to invest in EE and DG. It is true that a lower kWh charge does provide a lower incentive, but if the kWh charge properly reflects the variable cost of service, it is a more accurate incentive and is more consistent with principles of rate design.

Forcing utilities to include unspecified levels of fixed costs in the variable charge in order to subsidize investments in EE and DG denies both consumers and regulators the transparency required to make good investment and policy decisions.

Subsidizing EE and DG through poor rate design is also unsustainable. As DG penetration levels rise, utilities could be forced to recover the fixed costs of the system in fewer and fewer total kWh, forcing that charge up, increasing the hidden subsidy, creating greater political opposition to DG from those forced to pay the subsidy, and imposing greater financial risk on the utilities.

Recovering fixed cost with fixed charges can benefit low-income consumers

Some policy makers are concerned that revised rate designs that recover all of a utility's fixed costs through a fixed monthly charge may harm lower income consumers. However, lower income consumers are not necessarily low-usage consumers.

In cooperative territories, lower income consumers often live in the oldest and least energy efficient housing stock. They are least likely to have the resources to invest in weatherization, efficient HVAC systems and appliances, energy efficient housing and other conservation measures.

Lower income customers are often also the least likely to invest in distributed generation, because they lack the upfront cash, because they live in rental housing, or because they have other priorities. They are, therefore, the most likely to bear the cost of subsidizing DG investments through rate designs that fail to recover fixed costs of service from members with DG. According to a recent California Public Utilities Commission report, 78% of California consumers that have net metering have household incomes above the state median level*.

Straight-fixed variable rates are only one option for cooperatives whose traditional rate designs do not meet their needs as dg levels increase

Cooperatives' goal is to provide their members with safe, reliable, affordable power at fair rates that recover the cooperatives' cost of providing service. There are many ways to accomplish that goal and the appropriate approach will be different for each cooperative depending on their local circumstances, members, board, and management.

In addition to the straight-fixed variable approach discussed above, for example:

Some cooperatives have adopted 3-part rates for residential customers, like those often charged to commercial and industrial customers. Those rates divide charges between customer charges for such fixed costs as metering and billing demand, charges for fixed costs relating to the member's maximum demand on the system (such as generation capacity, distribution and transmission infrastructure), and variable charges that reflect the cost of providing members the energy they actually consume.

Other cooperatives have retained the traditional rate design, but layered on top stand-by charges or other member-specific charges for those members that install DG to recover from those customers the fixed costs of providing service.



**California Net Energy Metering (NEM) Draft Cost-Effectiveness Evaluation: NEM Study Evaluation," California Public Utilities Commission Energy Division, September 26, 2013*



The National Rural Electric Cooperative Association (NRECA) is the national service organization representing the interests of cooperative electric utilities and their consumers. In addition to advocating consensus views on legislative and regulatory issues, NRECA provides health care, pension and many other programs for its members.

NRECA | 4301 WILSON BLVD | ARLINGTON, VA 22203 | WWW.NRECA.COOP