CONNECTING TO THE GRID

WHAT'S INSIDE — March 2011

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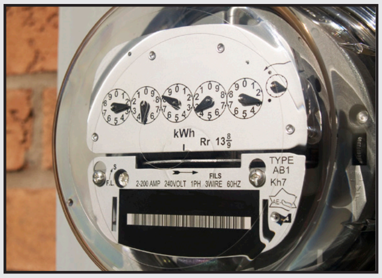

ABOUT THIS NEWSLETTER

While customer-sited net metering and interconnection policies are primarily addressed at the state level, they are also becoming important on a regional basis. This newsletter has been designed to provide state-level policy updates and capture emerging regional trends. *Connecting to the Grid* is a free, electronic newsletter published each month by the Interstate Renewable Energy Council (IREC) and the North Carolina Solar Center at North Carolina State University. Click here to subscribe.

Please direct comments and questions about the newsletter to Laurel Varnado at lavarnad@ncsu.edu.

IREC Interstate Renewable Energy Council

INNOVATING OUR WAY INTO THE GREAT UNKNOWN

Holy Cross Energy community solar array, operated by the Clean Energy Collective

However geeky this may sound, I think it's easy to liken the burgeoning policy movement known as Community Renewables to the opening of a Star Trek episode. And why not? We're attempting to explore strange new ideas, to seek out new life in the renewable energy world and boldly go where no policy has gone before. There, I said it.

While I have extolled the benefits of community renewables policies in past articles, I would like to acknowledge one of the challenges for these policies going forward—billing individual customer accounts based on energy production from a shared system. In other words, how does a utility or third party organization determine what a share of community solar actually amounts to each month? Some state policies, such as Delaware, base community renewables credits on a customer's kilowatt-hour rate, à la net metering style. Many other state policies are either somewhat vague on this issue of crediting or they allow the community group to organize and distribute credits among members as they see fit. From a billing perspective it may be easier to monetize the kilowatt-hours and provide bill credits on a customer's bill, depending on the structure of the policy or program and the utility's billing software. This is especially true when customers on different rate classes are participating in a shared system and receiving kWh bill credits for generation from the same solar facility. If the resulting energy is being assigned to customers on different rate classes it would essentially be given two different values (i.e. a residential customer receives a different kWh value than a commercial customer).

Because community renewables policies present a departure from traditional net metering, most utility billing software applications are not readily equipped to accommodate these policies, a challenge that has impeded utilities' willingness to participate. Integrating community renewables capabilities can often require costly billing software updates or administratively burdensome manual bill crediting. Manual crediting can work for smaller pilot programs but it is not generally scalable to larger programs or state-wide mandates.

Holy Cross Energy (HCE), an electric cooperative in western Colorado may have found an innovative way around this challenge though. In early 2010, HCE partnered with the Clean Energy Collective (CEC), a third party provider, to develop a 1(soon to be 3)MW community solar array. CEC developed a "RemoteMeter" billing software to integrate with HCE's billing system, so that the utility can download information into their own billing platform and accomplish the task of administering bill credits (or their monetary value). Third party interfaces are frequently used by utilities to share energy consumption data with their customers online, and this tool is gradually gaining acceptance as a creative billing solution for community renewables. Because the utility can view the data and download it into their system when they choose, it presents a secure and cost-effective means to address the billing challenge.

"To boldly go where no policy has gone before."

But it isn't simply a matter of distributing credits to participating customers. According to a CEC representative, they also have the need to track resale, meter transfer, rate change, credit change and then "some more complicated issues." Additionally, some regional building codes and programs require renewable energy investment so if a customer buys into a community array to comply with a code, the panels must stay with the property. So, the community solar investment must be tied to the real property and there must be billing software checks in place to do so.

Challenging? Yes. Impossible? Apparently not.

As community renewables policies gain ground in the U.S., we'll certainly be seeing other innovative solutions pop up to address some of these lingering questions. With all of the bright minds at work in the renewable energy industry, I'm sure community renewables will 'live long and prosper' (sorry, I couldn't help myself).

Regards,
Laurel Varnado

STATE NEWS IN DETAIL

NORTHEAST STATES

MASSACHUSETTS

On February 14 the Massachusetts Department of Public Utilities held a net metering and interconnection technical conference. The agenda for this conference specified the purpose of the technical conference was to engage in a discussion that identifies an assurance of net metering eligibility and other net metering and interconnection issues. This discussion comes as a result of a 2010 Act signed in October.

As a result of this technical conference, utilities that are bound by the net metering law must provide the following information to the DPU:

- Size, generation type, net metering class, rate class, and fuel type and the municipality where net metering facilities are located;
- Aggregate capacity of all net metered facilities in their service territory;
- The number of Class I, II and III Net Metering Facilities that have a municipality or other governmental entity as the Host Customer and the aggregate capacity of these;
- Size, generation type, anticipated net metering class, anticipated rate class, fuel type, anticipated in-service date and the municipality for facilities that have a pending request to interconnect;
- The aggregate capacity of the facilities that have pending requests to interconnect and to receive net metering services;
- The number of pending requests for anticipated Class I, II and III Net Metering Facilities that have a municipality or other governmental entity as the Host Customer and their aggregate capacity;
- Whether the Company has opted to pay a Host Customer for net metering credits rather than allocate them.
- The number of distributed generation facilities that have applied for interconnection and those that have been interconnected in the utility's service territory since 2005 on an annual basis (and, if available, on a monthly basis).
- Information on the quality of applications received from distributed generation facilities to interconnect in the Company's service territory since 2005, including a discussion of any follow-up needed to complete the application, the time and resources necessary to process applications and the impact, if any, of the adoption of the Green Communities Act in 2009.
- How the Company applies net metering credits to the bill of a customer who uses competitive supply.

For more information search for Docket 11-11 on the MA DPU File Room Web site.

NEW YORK

Beginning in late January the NY PSC initiated a proceeding requiring all utilities in the state to explain how they credit net metered customers for excess generation that is exported to the grid.

As specified in the current net metering rules, residential solar, farm waste, residential wind, and farm service wind customers are reimbursed at the utility's avoided cost for any excess generation remaining at the end of an annual period. Some utilities require that a residential solar net metering customer cash-out the reimbursement of the annual excess credits exactly at the one year interval from the date the customer's solar facility commenced operation. If that date falls soon after the summer period of high solar production, the solar customer's NEG credits that have accumulated during that period would be cashed out at avoided cost, which is substantially less than the tariff rate. An adjustment to the timing of the date for the annual cash-out would avoid this disadvantage to residential solar customers.

For demand net metered customers, the excess generation, in kWh, accumulated during a billing period is multiplied by the applicable tariffed kWh rates and that credit is subtracted from the current bill. If the amount of the credit exceeds the amount of the bill, the excess amount is converted, at kWh rates, back to a kWh figure, which is subtracted from usage during the next billing period, before the next credit is calculated.

As specified in the order (linked below) it appears that utilities may not be properly reflecting all kWh rates set forth in their tariffs when calculating the billing credit and converting any excess credits back to a kWh figure. The treatment of various kWh delivery charges, and of other items like the Systems Benefits Charge (SBC), the Renewable Portfolio Standard (RPS) charge, the Energy Efficiency Portfolio Standard (EEPS) charge, and the Temporary State Assessment Surcharge, may differ among utilities.

Moreover, the order notes that residential solar net metered customers should not be disadvantaged by the timing of their annual cash-out of their avoided cost reimbursement, as happens when that cash-out takes place soon after the summer period. To prevent this outcome, a residential solar customer should be permitted to exercise a one-time waiver of its annual cash-out date, delaying the cash-out until the next subsequent May 1 date. Thereafter, the cash-out would occur annually on May 1 of each year.

Accordingly, the six major electric utilities that offer net metering were required to submit, by March 4, 2011, a statement evidencing that they either: 1) already recognize all kWh rate components, including, but not limited to, any charge for delivery (including adjustment charges) and the SBC, RPS, EEPS, and Temporary State Assessment Surcharge charges, in their calculations of net metering credits; or 2) will revise their calculation methods to so recognize all such components by June 1, 2011; or, 3) protest that should not be interpreted as requiring them to recognize all kWh charges in performing the calculation.

Reply comments to both the utility and interested party filings are due on April 4, 2011.

See the initial order for Case Matter 10-E-0645 for more information.

MID-ATLANTIC STATES

DELAWARE

There is a net metering workshop scheduled for March 24, 2011, for Delaware PSC docket 49. This docket was established to carry out Senate Bill 267, enacted in 2010, which improved Delaware's net metering law by increasing the amount of energy customers can sell back to the grid (i.e. 110% of their aggregate consumption). Also, customers, such as a business campus or agricultural operations can aggregate several meters for multiple locations to determine how much power can be sold back through one meter. In this way, customers will be able to finance larger renewable energy installations to meet their needs. Finally, homeowner associations and similar groups of customers sharing a unique set of interests will be able to cooperatively finance and build community-scale renewable energy projects both on and off-site.

MARYLAND

In late February the Maryland Public Service Commission issued proposed rules regarding net metering. The proposed rules contain two main departures from the current rules, one of which is a step forward, the other a step back for net metering.

Following a mandate from Senate Bill 355 in 2010, the proposal specifies that an electric utility must convert monthly net excess generation from kilowatt hours to generation credits by multiplying the metered excess generation by the hourly locational marginal price (LMP) as established by PJM. Generation credits would then appear on the customer's bill in a dollar amount. However, when net energy metering is provided by a municipal or electric cooperative whose avoided cost of generation is a contracted energy rate, the municipal or cooperative must convert excess generation from kilowatt hours to generation credits by multiplying the metered excess generation by the contract rate. This is a departure from traditional net metering in that linking NEG to the hourly LMP would most likely devalue the customer's net excess generation, especially in the case of wind energy.

On a positive note, however, the proposed rules also allow for both physical and virtual net metering for non-profit, agricultural and government customers. Those wishing to aggregate meters must provide written allocation instructions detailing how to distribute excess generation credits to each account. If a customer's accounts are not located close enough to physically interconnect, the electric utility must sum the usage and excess generation of all applicable accounts on a kilowatt-hour basis over each billing period, prior to calculating the customer's excess generation for that billing period (as in virtual net metering).

It is unclear at this time whether this proposal will be adopted since the way the law was written arguably contradicted legislative intent.

Refer to a previous IREC post for background on this issue.

MIDWESTERN STATES

MICHIGAN

The Michigan Public Service Commission (MPSC) announced on February 8, 2011, that it is seeking public comments related to electric interconnection and net metering documents previously approved for interim use.

Specifically, the MPSC is seeking comments on the proposed Category One interconnection agreements and applications. Category One projects involve all inverter-based projects with aggregate generator output of 20 kilowatts or less.

In addition, the MPSC is seeking comments on interconnection process flow diagrams for all projects.

Any person may submit written or electronic comments regarding the proposed interconnection procedures and forms attached to the application. Comments must be filed with the MPSC no later than March 10. Reply comments are not provided for. All comments should reference Case No. U-15919.

Source: MI PSC News Release

OHIO

The Public Utilities Commission of Ohio recently rejected Duke Energy Ohio's application to transition to a completely market-based system for establishing its electric generation rates. Duke's rates are currently set pursuant to a three-year price formula negotiated in an electric security plan (ESP) that expires on December 31, 2011.

Under Ohio law, a utility that still owns electric generating facilities, such as Duke, can transition to wholly market-based rates over a five-year period. In its application for a market rate offer (MRO), Duke interpreted the statute in question to mean that it could shorten the transition period to two years. The Commission disagreed and concluded that Duke's application cannot proceed as filed. The question now is whether Duke will re-file its application as an MRO or an ESP, the choice preferred by the Commission staff. Refer to PUC case 10-2586-EL-SSO for more information.

Source: Bricker & Eckler LLP

SOUTHERN STATES

NORTH CAROLINA

The North Carolina Utilities Commission recently released the application to register a renewable energy facility with the commission. According to commission rule R8-66, the owner of a renewable energy facility that intends to sell electric power or RECs to a utility for compliance under the state's Renewable and Efficiency Portfolio Standard (REPS), must first register the system with the NCUC. This applies to all non-utility generators, whether in-state or out-of-state, certificated or exempt from certification, metered or non-metered. As part of this registration, each generator is required to annually file with the Commission the generation data that they annually file with the Energy Information Administration, U.S. Department of Energy.

Utilities' compliance with the North Carolina REPS is tracked through the NC RETS system. The registration application is available on the NCUC Web site.

WESTERN STATES

COLORADO

On March 4, 2011, the Colorado Public Utilities Commission told Xcel Energy Inc. and the state's solar power industry to work out an agreement on rebates for small-scale solar power systems at homes and businesses, which Xcel is trying to reduce. The two sides were given a seven-day deadline.

The commissioners, during a three-hour hearing, said they'd consider approving a settlement, if one is reached, on March 11. If no agreement is reached by then, the commissioners said Friday they may take steps to resurrect Xcel's Solar*Rewards rebate program in some form on a temporary basis until long-term decisions can be made.

The battle between Minneapolis-based Xcel and the companies that install small-scale solar power systems in the utility's Colorado service territory started Feb. 16, when the utility abruptly cut rebate levels for the solar power systems from $2.35 per watt to $2.01 per watt. The utility closed the program to new applications the following day, meaning new solar power systems sold after Feb. 17 are not eligible for a Solar*Rewards rebate until Xcel reopens the program.

The Colorado Solar Energy Industries Association (CoSEIA) says solar power sales virtually halted when Xcel shut down its rebate program and layoffs are looming for many companies in the industry.

“We’re happy to come to the table with the solar industry to try to reach an agreement,” said Michelle Aguayo, a spokeswoman for Xcel. “It’s always been our goal to get this program restarted in a form that is fair and equitable.”

Xcel has asked the PUC to cut the rebate levels to $1.25 per watt. CoSEIA wants the commission to keep rebates flowing — at some level — until commissioners make a decision to approve or deny Xcel’s request.

“The PUC is moving very quickly on this issue, reinforcing the fact that they see the need to get this resolved before there’s any more economic damage to this industry,” said Neal Lurie, CoSEIA’s executive director.

Money for Xcel’s Solar*Rewards rebate program comes from a 2 percent surcharge on the monthly bills of the utility’s 1.3 million Colorado customers.

Source: Denver Business Journal

Also in Colorado, the Delta-Montrose Electric Association (DMEA) has established a Community Solar Array program after completing two solar arrays, with combined capacity of 20 kilowatts (kW). The Community Solar Array program is selling shares of these arrays to consumers in blocks of $10 per 2.67 watts ($3.75/watt). DMEA expects that a 2.67 watt share will produce $0.50 of electricity for the consumer on an annual basis; consumers will receive a credit for the production of their share of the solar array. Participating customers will receive credit at the full retail rate, currently $.09703/kWh for residential customers, for the production of their solar share. The length of the lease is 25 years, and DMEA will own and maintain the solar array over that time period.

Source: EERE Green Power Network

IDAHO

The Idaho Public Utilities Commission has established a schedule in a case seeking the best way to allow small wind and solar developers to qualify to be paid commission posted rates.

On Feb. 7, the commission ruled that wind and solar project developers who want to be paid the commission posted rate can be no larger than 100 kilowatts during the period that this case is processed. Previously, projects up to 10 megawatts could qualify for the published rate. The 10 MW upper limit remains for non-wind and non-solar renewable projects.

Parties who want to intervene in the case for the purpose of presenting evidence and cross-examining witnesses must file petitions to intervene with the commission by no later than March 4. Those parties who were part of the previous docket leading up to this case (GNR-E-10-04) are automatically included as intervenors in this case.

Pre-file direct testimony and exhibits will be accepted through March 25 with rebuttal testimony and exhibits due April 22. The commission will then conduct a technical hearing beginning Tuesday, May 10, at 9:30 a.m. in the commission hearing room, 472 W. Washington St. in Boise. The hearing may continue, if necessary, through May 13.

Idaho’s three major regulated electric utilities – Idaho Power Company, Avista Utilities and PacifiCorp – contend that a rapidly expanding number of wind projects is having a profound impact on customer’s rates and reliability. The utilities contend that large-scale wind farms are breaking up their projects into smaller 10-MW increments in order to qualify for the published rate, which is typically more attractive than rates for projects larger than 10 MW.

The published rate is called an “avoided-cost rate” because it is to be based on the cost the utility avoids by buying power from the small-power producer and, thus, not having to build the generation itself or buy power from another source.

Small-power producers can have their projects declared Qualifying Facilities (QFs) under the provisions of the federal Public Utility Regulatory Policies Act (PURPA) passed by Congress in 1978 to promote the development of renewable energy technologies. PURPA requires electric utilities to buy power generated by QFs at the avoided-cost rate determined by state commissions. Commissions must publish avoided-cost rates for projects with a design capacity of 100 kW or less. However, the commission has the discretion to set the published rate at a higher amount and, until recently, the commission has established a 10 MW eligibility cap.

The commission must ensure the avoided-cost rate is reasonable for utility customers because 100 percent of the price utilities pay to QFs is included in customer rates. Federal rules regulating PURPA development insist that rates for purchases from QFs be “just and reasonable to ratepayers and in the public interest – not in the interest of the QFs," the commission stated in its Feb. 7 order.

The three utilities claim the small-power projects PURPA was originally intended to encourage are now often developed by sophisticated large-scale wind farms that break up, or disaggregate, large wind projects into several smaller projects in order to qualify for the published avoided-cost rate. When combined, these projects can total up to 100 or 150 MW interconnecting at one delivery point. The rapid expansion of these projects is causing a strain on utility transmission systems which can affect electric reliability, the utilities claim.

On Feb. 7, the commission said the utilities made a "convincing case," to temporarily reduce the eligibility cap for wind and solar projects only until these issues can be resolved. The 100-kW cap does not include all types of renewable projects, such as biomass, hydro, geothermal and anaerobic digestion, because these types of projects do not pose the same type of issues as those posed by wind and solar. The latter two are intermittent and must be backed-up by other generation when the wind does not blow or when the sun does not shine. Further, large-scale wind and solar projects can be broken up into smaller projects to qualify for the published rate.

In this case, the commission is soliciting information and investigation of an avoided-cost rate cap structure that allows wind and solar QFs that are 10 MW or smaller to again qualify for published rates while also preventing large QFs from disaggregating their projects to qualify for a rate exceeding true avoided cost.

"The commission is supportive of all small-power producers contemplated by PURPA, including wind and solar, and it is not the commission's intent to push small wind and solar QF projects out of the market," the commission said in its Feb. 7 order.

Source: Idaho PUC Press release

MONTANA

From a Montana PSC press release, the Montana Public Service Commission is advising federal rule makers that "cost causers" should pay when it comes to the extra capacity needed in an electricity system when variable energy resources are used. Additional regulating reserves must be available to "the grid" to balance load and energy when variable energy resources, such as wind energy, fluctuate in their moment to moment generation. Not supplying these additional regulating reserves is not an option. For example, Northwestern Energy, as a balancing area operator, must maintain an energy and load balance within North American Reliably Corporation Standards at all times or face substantial federal fines. The PSC voted February 24 to submit comments to the Federal Energy Regulatory Commission (FERC) stressing that energy generation sources with variable output should bear the cost of keeping additional capacity resources available for the periods when a variable energy producer, such as a wind plant, does not produce a consistent energy product. The comments are in response to FERC's Notice of Proposed Rulemaking on the Integration of Variable Energy Resources, Docket RM10-11-000.

In addition to the Commission's comments, the PSC has joined as a signatory to the Organization of MISO States (OMS) comments to FERC that also stress the principle of cost causation. MISO is the Midwest Independent Transmission System Operator, which monitors and coordinates the operation of the electric transmission

UPCOMING EVENTS

SolarTech Leadership Summit
March 29-30
Santa Clara, CA

PV AMERICA
April 3 - 5, 2011
Philadelphia, PA

10th Annual Southern BioProducts and Renewable Energy Conference
May 10-11, 2011
Biloxi, MS

ASES Solar 2011
May 17-21
Raleigh, NC

Intersolar
July 12-14
San Francisco, CA

Visit IREC's online calendar for more details and events. If you have events you'd like to include in this newsletter, contact us.

system in 15 Midwestern states, including eastern Montana, and parts of Canada.

OTHER STATES

HAWAII

Kauai is a small island with a daytime peak demand that usually falls in the 60 – 70 MW range. The island has around 4 MW of customer sited distributed PV, in addition to the utility's first purchase power agreement for a 1.2 MW plant, so on a sunny day PV meets about 7-9% of the island's peak power needs. This level of penetration is already much higher than that experienced by mainland utilities in the US, but it is below the penetration levels of 15-30% at which concerns arise about grid instability caused by variable output generation sources.

Kauai provides an ideal environment for isolating the impact that PV penetration level has on grid instability, because the island has no wind farms. In fact, it may never have a wind farm, due to the presence of federally endangered seabirds. Solar PV, on the other hand, is well established and rapidly growing; with the potential to meet 20% or more of the island's peak power needs on sunny days within the next few years.

There are a few concerns utilities have about high penetration PV, but the primary one focuses on ramp rates: picture a sunny day with a few clouds rolling by, which cause a PV system's output to swing abruptly between its maximum output and a much lower level. The other generation on the system must make up for the variable output before voltage and frequency levels on the system drop too low or go too high. If the other generation cannot respond fast enough, power quality on the grid will be adversely affected as voltages and frequencies fluctuate to unacceptable levels.

As long as the penetration of PV on the grid is low, the utility should have no trouble maintaining power quality as the output from PV systems fluctuate. However, even if overall PV penetration levels in a region are low, it is possible to have local "hot spots" where penetration on a single distribution circuit is very high. In this case utilities have concerns that power quality will suffer on that distribution circuit due to the high penetration of PV. KIUC is testing that hypothesis to the extreme with its 1.2 MW solar farm, by supplying 100% of a distribution circuit with PV during the day.

Now for the good news: as the utility monitors the distribution circuit on sunny days and cloudy days, with the PV system turned on and the PV system turned off, they are seeing very little difference in the voltage levels, harmonics, and overall power quality between the different scenarios. These preliminary results suggest that utilities could go to very high levels of PV penetration in localized areas without causing problems for the grid. KIUC is continuing to monitor the system, but the initial results look very positive for the PV industry.

As PV penetration on the island grows, KIUC will have the opportunity to evaluate the impact of high penetration levels of PV over the whole island grid (as opposed to just a single distribution circuit). The potential for power quality issues is much greater when overall PV penetration levels become high, which is why KIUC has begun investing in battery energy storage systems to mitigate the potential impact from such a high concentration of PV. This initial battery investment with be programmed to control the ramp rate for a planned 3MW PV farm and provide system wide frequency support. Whatever KIUC finds, this will be an important island to keep an eye on as utilities prepare for ever increasing penetration levels of PV.

Source: IDC Energy Blog

MISCELLANEOUS NEWS

FEDERAL TRADE COMMISSION PROPOSES RULES FOR GREEN POWER MARKETING, RECS

Navigating the yellow brick road of green power marketing can be challenging for consumers and marketers alike. As a result, the Federal Trade Commission (FTC) recently proposed draft guidance on renewable energy (RE) claims in advertising. However, one clarification might create a marketing challenge for third-party ownership models. It states that if renewable attributes from your on-site generation are sold, you cannot claim to "host" that system (a claim that is currently standard practice).

In October 2010, the FTC—which regulates marketing to protect consumers—issued draft revisions to its "Guides for the Use of Environmental Marketing Claims" (hereafter, referred to as "Guide"). It proposes new guidance for claims not addressed in the current Guide, including "Made with Renewable Energy," "Made with Renewable Materials," and "Carbon Offsets" (the latter two are not addressed here).

What are the details behind the curtain? Some of the “Made with Renewable Energy” provisions were in line with market expectations. First, the FTC clarified that RE claims can be based on renewable energy certificates (RECs). This clarification has two specific implications: the marketer does not need to have a contract for the underlying power from the renewable generator, and the marketing does not need to state that RECs are the specific basis of the environmental claim. In other words, the text does not need to clarify that RECs were purchased to offset conventional generation because “there is no reason to believe that this fact would be material to consumers.”

Second, the owners of the RECs are the ones able to claim that they use RE. For example, if project owners sell the RECs from their on-site generation, they cannot claim that they use renewable power. This, in turn, ensures that the RECs are only used, and claimed, once. While these first two provisions were not surprising, it was the first time that the FTC commented on these issues.

However, some of the FTC clarifications will affect current green power marketing practices. The main implication of the Guide’s revisions is that there cannot be any vague claims of “made with renewable energy.” Rather, marketers must clarify and qualify:

• The source of RE (e.g., wind or solar)
• The percentage of RE used (if less than 100%).

Clarifying the source and mix of your green power will be easier for some marketers than others. Robin Quarrier, Green-E Analyst and Counsel with the Center for Resource Solutions, explained that this is “easy to do if you use 100% wind.” But identifying the percentage and resource will be more complicated if you have to list several percentages for two or more renewable resources. Specifying resource mix will be particularly challenging if the marketer’s mix changes depending on the types of RECs available for sale in the spot market.

Source: Karlynn Cory, NREL

FERC IMPROVES COMPENSATION FOR FREQUENCY REGULATION

At its February 17, 2011 meeting, FERC approved a proposed rule to improve compensation for resources that provide frequency regulation service in organized electricity markets by acknowledging the benefits of their fast response. This proposal will better recognize the value of quick responding innovative resources such as storage technologies and demand response. Commissioner Spitzer dissented because he does not think the record is adequate to make a specific compensation proposal.

FERC approved a Notice of Proposed Rulemaking (NOPR) to establish a uniform approach to compensating resources that provide frequency regulation service in organized electricity markets. Frequency regulation service protects the grid by correcting deviations in grid frequency. When generation dispatch does not equal actual load and losses on a moment-by-moment basis, the imbalance will result in the grid’s frequency deviating from the standard (60 Hertz). Maintaining the frequency of the transmission system within an acceptable range is critical to reliable operations. Major deviations cause generation and transmission equipment to separate from the grid and, in the worst case, lead to a cascading blackout.

According to FERC, frequency regulation service corrects frequency deviations by injecting or withdrawing power from the grid. The faster a resource can increase or decrease its output, or “ramp up or down,” the more accurately it can help correct frequency deviations. While generators have historically provided the power to regulate or correct frequency deviations, new non-traditional technologies such as large-scale battery systems, flywheels, electric vehicle-to-grid systems, and demand-side processes, have the ability to ramp up or down faster than some traditional resources and, as such, are able to provide frequency regulation services more accurately than traditional resources. Faster-ramping resources can improve the operational and economic efficiency of the transmission system and lower costs. For example, these resources use less regulation capacity and free slower-ramping resources to operate at more efficient heat rates.

According to the NOPR, however, faster-ramping resources are compensated at the same level as slower ramping resources in most RTOs and ISOs. This is because compensation is limited to a capacity payment and net energy balancing, which results paying both fast-ramping and slow-ramping resources the same amount if they both set aside the same amount of capacity to provide the service. However, the value of a resource’s capacity in providing frequency regulation is based on and limited by its ability to ramp up or down in five minutes, which is the interval between dispatch instructions from the grid operator. A resource with a relatively large amount of capacity but a relatively slow ramp rate would be limited in how much capacity it could offer for regulation.

Source: Covington and Burling, LLP

SOLAR INDUSTRY SEES RECORD GROWTH, ACCORDING TO SEIA REPORT

The U.S. solar energy industry had a banner year in 2010 with the industry's total market value growing 67 percent from $3.6 billion in 2009 to $6.0 billion in 2010, according to the U.S. Solar Market Insight: Year-in-Review 2010 released today by the Solar Energy Industries Association (SEIA) and GTM Research. Solar was a bright spot in the U.S. economy last year as the fastest growing energy sector, contrasting overall U.S. GDP growth of less than 3 percent.

In total, 878 megawatts (MW) of photovoltaic (PV) capacity and 78 MW of concentrating solar power (CSP) were installed in the U.S. in 2010, enough to power roughly 200,000 homes. In addition, more than 65,000 homes and businesses added solar water heating (SWH) or solar pool heating (SPH) systems.

The U.S. PV market made the most significant strides in 2010, more than doubling installation totals from 2009 according to the latest U.S. Solar Market InsightTM report. This expansion was driven by the Federal section 1603 Treasury program, completion of significant utility-scale projects, expansion of new state markets and declining technology costs.

The section 1603 Treasury program helped fourth-quarter installations surge to a record 359 MW and was critical in allowing the solar industry to employ more than 93,000 Americans in 2010. Originally set to expire at the end of 2010, the 1603 Treasury program was ultimately extended through 2011.

In addition, market diversification was a distinguishing characteristic of U.S. solar energy development in 2010. Sixteen states each installed more than 10 MW of PV in 2010, up from only four in 2007. The top 10 states for PV installation in 2010 were: California, New Jersey, Nevada, Arizona, Colorado, Pennsylvania, New Mexico, Florida, North Carolina and Texas.

Cost declines were also an important factor in the 2010 solar expansion, as technology costs fell and the industry matured further, capitalizing on greater economies of scale and improved installation practices. In the residential and commercial-property segments, installed annual PV system cost declines of 8 percent and 11 percent respectively spurred record build-out.

highlights from U.S. Solar Market Insight: Year-in-Review 2010:

• The total value of U.S. solar market installations grew 67 percent from $3.6 billion in 2009 to $6.0 billion in 2010.

• Solar electric installations in 2010 totaled 956 megawatts (MW) to reach a cumulative installed capacity of 2.6 gigawatts (GW), enough to power more than half a million households.

• Grid-connected PV installations grew 102 percent in 2010 to reach 878 MW, up from 435 MW in 2009, bringing cumulative installed PV capacity in the U.S. to 2,086 MW.

• Sixteen states installed more than 10 MW of PV in 2010, up from four states in 2007.

• Utility PV installations more than tripled in 2010 to reach 242 MW, up from 70 MW brought online in 2009.

• U.S. manufacturing of PV components increased substantially year-over-year for wafers (97 percent growth), cells (81 percent growth), and modules (62 percent growth).

Source: SEIA News Release