Alternative Rates and Tariffs for Distributed Generation Resources (DGR's)
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The following are Larry Schedin's comments after working on behalf of many DGR's around the U.S.

A. Rates and Tariffs Must Relate to a Wide Range of Buy-Sell Configurations

Customer installations of DGR facilities fall into several basic categories with respect to tariffs.

1. <u>Those that use all the energy on site</u>. In this case, the customer utilizes generated output to displace electricity otherwise supplied under a standard, bundled utility tariff or under open access by a third party. Although the customer can calculate savings based on their regular electric bill, this configuration raises some very serious issues along with the risk of unrealistic saving expectations. Questions arise such as:

   a. Does the customer generate all or only part of their total requirements? If the customer does not generate all of their electrical requirements, is the customer placed on a different (usually higher) tariff for supplemental service because of reduced utility consumption or other reasons?
   b. Does the reliability of the DGR and the customer's usage require standby and maintenance services from an outside source (typically the local utility)? i.e., if the customer lacks generation redundancy and cannot interrupt load, then standby service will be required either from the local utility or a third party source.
   c. Can standby services be provided from a third party separate from the local utility? This issue is accompanied by issues of wheeling both on the local distribution system and the transmission system.
   d. How should standby and maintenance rates be designed? Utilities typically fail to recognize diversity among DGR users.
   Certainly, the class of DGR users like utilities themselves, can be analyzed as a separate class using probability methods to calculate reserve requirements as a group to be used as a basis for standby costs. Utilities typically use "once in 10 years" as their risk threshold as mandated by the National Electric Reliability Council (NERC).
   e. Does loss of utility load to DGR sources leave distribution and other facilities stranded? Utilities often argue for increased distribution charges due to under utilization. This is quite often the claim when an existing customer installs DGR resources. Some states impose Competitive Transition Charges (CTC's) as a means for recovering stranded costs on load lost to generation even for new customers.

f. How are demand ratchets assessed? Demand ratchets are minimum billings brought forward from usage in prior months.

2. Those that sell all the DGR energy to an off-site party. In this case, complications typically arise when determining the value of electricity sold off site.

   a. Local utilities typically purchase at their avoided costs. Avoided costs are very ambiguous concepts when considering the range of avoided costs from avoided marginal (fuel plus operating) costs to avoided unit installation (or purchased capacity) costs. Local utilities typically opt for the lowest price. In Minnesota it's difficult to tie a DGR to avoided installation costs because of the mandated bidding process for new capacity.
   b. Sales into the market. Sales to destinations remote from the local utility or to other customer-owned sites on the local utility's system are often difficult or impossible due to the requirements for wheeling over the local utility company's distribution system. Such wheeling service is not mandated by FERC under open transmission access unless the DGR is directly connected to a high-voltage substation. Such a hook-up is not feasible for small DGR's. However, markets are emerging which can provide hourly pricing signals from remote markets to a DGR as a decision variable on which to base operating decisions. Local transportation remains a key issue for small DGR's when moving electricity off site.

3. Intra-site Wheeling

   Utilities often own the primary distribution cables within a plant site which requires multiple delivery points. This is a common situation even though the customer installs and pays for duct line. Local utility rules often prevent such a customer from wheeling from one load point to another within the plant site. This presents a major barrier at some plants because of limited loads at one delivery point cannot utilize all the plant generation at that delivery point.

4. Hybrid arrangements with both electric bill displacement and off-site sales. It is important to note that a DGR customer can be purchasing all of its on-site electric needs from an off-site source while simultaneously selling 100% of the generated output to an off-site market.

   Additionally, further hybrids exist when a customer may elect to purchase from off-site resources at certain times and to sell to off-site markets at others. For example, because of high fuel cost, it may be most prudent to generate during high-cost hours and shut down and purchase from off-site resources at off-peak hours. Hybrid configurations present combinations of the foregoing barriers.

B. Rates and Tariffs Must Relate to a Wide Range of Operational Designs

The wide range of operational designs encompass:

1. Peak shaving operation to reduce peak period electric bills or to release capacity into markets during periods of high utility costs or tight capacity situations.
2. Base load operation often designed to meet steady process heat loads. These facilities often apply cogeneration which is the simultaneous production of electricity and by-product heat from a single fuel source. Cogeneration facilities which meet minimum efficiency standards as well as certain other generating facilities fueled by renewables already have special treatment under the Public Utility Regulatory Policy Act of 1978 (PURPA). Certification under PURPA is called a Qualified Facility (QF). However, QF benefits often fall short when removing barriers to DGR.
3. Intermediate modes of operation based on fluctuating heat loads or fuel cost changes. These facilities are sometimes labeled combined heat and power (CHP) and include back-pressure turbines as part of district energy systems.
4. Intermittent operation due to the availability of wind, biomass and other renewables.

C. Other Issues

1. Feeder loading relief along with reduced system losses and avoided T&D costs should result in benefits for locating DGR's at heavy load points on a distribution system.

2. Special rate contracts. Minnesota has a plethora of special power purchase rates for facilities under special contracts. Examples include St. Cloud hydro and the Fibro-Minn project at Benson (under the Prairie Island mandate). These rates are typically negotiated to meet the developers threshold needs for ROI. Mandated facilities may have the advantage of excess cost subsidization by all ratepayers.