Success depends upon previous preparation, and without such preparation there is sure to be failure. Confucius

Not long ago, a man with a South African accent proclaims to an excited LA auditorium that he is there to announce “a fundamental transformation in how the world works”. Elon Musk continues, introducing Tesla Motors’ newest foray into energy storage: the Powerwall home battery. Residential energy storage in 7 or 10 kWh slugs in a box roughly 3’ x 5’ in size.

Traditionally, residential rate design has done an imperfect job of recovering fixed costs appropriately. For decades, the standard residential rate has consisted of a customer charge and a consumption-based charge. The customer charge is a fixed amount billed each month regardless of energy consumption. There are, of course, many different forms this basic model can take, but the key fact is many fixed costs are recovered through the variable rate component (e.g. the energy charge). There were several reasons this was (or, more likely still is) the case, including lack of affordable interval metering technology.

As a result, when electricity consumption declines in the residential class (due to, say, mild weather), fixed cost recovery is hampered because so much of the price is tied to consumption. With residential revenues making up a significant portion of total revenues, utilities can experience tough financial times when residential sales are down. Furthermore, advances in technology that give customers the ability to replace or reduce electricity they used to buy from the utility threatens the cost recovery under traditional rates.

A couple of empty-nesters go on a camping vacation and discover solar-powered camping gear. A few weeks later, they’ve transformed their fascination with the gear into purchase of solar panels on the roof of their rural home. Their first order of business is to call the electric coop and ask for “one of those meters that spins forward and backward.”
In a typical electric cost of service study, there are three kinds of fixed costs: customer costs, generation and transmission demand costs, and distribution demand costs. Customer costs are represented by the costs associated with producing a bill and by a theoretical minimum plant investment associated with serving a first kilowatt-hour to a customer. Distribution system demand costs are costs associated with the additional investment in excess of the minimum plant.

Quite a few utilities are beginning to increase the monthly customer charges in their residential rates. This is a first step toward better aligning recovery of customer-related costs through fixed prices. Even making a large increase in the customer charge to fully recover all customer-related costs is still leaving a large portion of fixed cost recovery in energy charges. Remember the distribution demand costs.

Another problem with increasing just the customer charge is that it is a “one size fits all” approach which may negatively impact sensitive customer types such as those on a fixed income, low income, or low use customers. Low use and low demand consumers may be unfairly impacted if a utility’s customer charge exceeds the customer-related costs and begins to recover some demand-related costs as well.

A Millennial has been raised in an environment of energy efficiency and conservation. He looks forward to a day without an electric grid, convinced he’ll see it in his lifetime. In the meantime, he’s well aware he needs the power produced by the local municipality to support his connected, tech-heavy life. However, he looks for every opportunity to enact the latest generation of efficient products and behaviors in his condo while adding consumer electronics to his stockpile at a rapid pace.

So, what do the Powerwall, solar panels, and conservation behaviors have to do with residential rate design? These all expose the weakness of recovering fixed costs under traditional residential rate structures. Consider, for example, that one industry analyst thought it possible that a Powerwall coupled to a solar panel array might result in a homeowner that buys little to no power from the utility during summer months and buys a lot in the winter. Imagine those distribution facilities sitting idle for months at a time! And, according to the Solar Energy Industries Association (SEIA), residential solar has posted annual growth rates over 50% in 2012, 2013, and 2014.

In response to these challenges, utilities are beginning to seriously consider residential demand rates as a viable option. In the past, just the mention of such could result in visions of pitchforks and flaming torches. But now, it’s a brave new world and one in which better aligning prices with cost causation not only makes a lot of sense but may be vital to financial survival. But moving in the demand rate direction is not a simple matter, like an aircraft carrier changing course. Several challenges await the progressive utility manager who begins to investigate residential demand rate design.

If not already deployed, utilities will soon be moving toward deployment of AMI and will therefore have the capability to measure demands at the individual household level. But defining the billing demand to use in a rate can be challenging. For instance, just a couple of the pros and cons associated with using a non-coincident or a coincident peak demand are shown in Figure 2.

Data quality and availability may also be an issue. A manager may think his utility is collecting and storing interval data with regular

continued on page 3
utilities are beginning to seriously consider residential demand rates as a viable option

For more information or to comment on this article, please contact:

Jake Thomas, Senior Project Manager
GDS Associates, Inc. - Marietta, GA
770.425.8100 or jacob.thomas@gdsassociates.com

Sources
1) Those costs that do not vary with the amount of energy consumed by the consumer, such as distribution system investment or capacity costs.
Transmission dependent utilities (TDUs) have to sort through a myriad of ancillary service schedules that are contained within the open access transmission tariffs (OATT) of their electric transmission service providers. **What are these “ancillary” services? Which ones need to be purchased? What is the basis for the charges under the various ancillary service schedules?** For the generation based ancillary services, can the service be self-supplied with customer-owned generating resources or other non-generation resources?

“Ancillary Services” are services supplied mostly from generation resources to facilitate (or are “Ancillary to”) the delivery of and reliability of power over the transmission system and fortunately, the answers to the preceding questions are not as daunting as they may seem.

Under the Federal Energy Regulatory Commission's (FERC or Commission) Order Nos. 888 and 890 pro forma OATT, FERC established seven ancillary service schedules consisting of:

- **Schedule 1** Scheduling, System Control & Dispatch Service
- **Schedule 2** Reactive Supply and Voltage Control from Generator Other Source Service
- **Schedule 3** Regulation and Frequency Response Service
- **Schedule 4** Energy Imbalance Service
- **Schedule 5** Operating Reserve – Spinning Reserve Service
- **Schedule 6** Operating Reserve – Supplemental Reserve Service
- **Schedule 9** Generator Imbalance Service

The seven ancillary service schedules listed above are the schedules that are most commonly included in transmission providers’ OATTs. While the costs for these ancillary services are fairly low (less than 5%) relative to the total delivered cost of power, they do become more significant for electric utility owners of intermittent resources, such as wind and solar. In addition, these costs will mostly likely continue to increase as electric utilities pursue cost recovery for new ancillary services. For example, some utilities have recently sought FERC approval for a new Schedule 6A to cover “Flex Reserve Service.” For simplicity purposes, this article only addresses the ancillary services under the seven schedules mentioned above.

FERC jurisdictional utilities must seek the Commission’s approval for the rates, terms and conditions for the ancillary services that are provided under their respective OATTs. Non-jurisdictional utilities do not fall under the purview of the Commission and, therefore, do not need to seek FERC approval of their ancillary services rates. However, a jurisdictional utility may refuse to provide OATT services (including ancillary services) to a non-jurisdictional utility if the non-public utility refuses to provide reciprocal services. TDU’s have certain rights under the Federal Power Act that provides them with the opportunity to question the justness and reasonableness of the ancillary services rates charged by transmission providers.

Regional Transmission Organizations (RTOs) with established ancillary services markets provide opportunities for TDUs to sell ancillary services from their generating resources. Of course, in this kind of market the TDU will face a more competitive environment which will somewhat limit the amount of sales it can make from its resources.

**Schedule 1 SCHEDULING, SYSTEM CONTROL & DISPATCH SERVICE**

These services include the scheduling of the movement of power through, out of, within, or into a control area (or balancing authority). The transmission customer must purchase Schedule 1 services from either the Transmission Provider or the Control Area Operator, to the extent they are not one in the same. Transmission customers are required to acquire Schedule 1 services regardless of the form of transmission service purchased.

continued on page 5
The rates for Schedule 1 service are typically derived based on certain costs booked by the transmission provider to FERC Account No. 561, which include the expenses related to load dispatching and scheduling, system control and dispatch services.

Schedule 2 REACTIVE SUPPLY & VOLTAGE CONTROL FROM GENERATOR OTHER SOURCE SERVICE

These services maintain transmission voltages on the Transmission Provider’s transmission facilities within acceptable limits using generation facilities and non-generation resources capable of providing reactive power. Similar to Schedule 1 service, the transmission customer must purchase Schedule 2 services from either the transmission provider or the control area operator. However, the transmission customer may be eligible for credits subject to the business practices of the transmission provider. These credits are usually for the reactive supply and voltage control capabilities provided by the transmission customer’s generation resources.

The rates for Schedule 2 service are typically derived based on the fixed production costs of certain equipment that is required for producing or absorbing reactive power.

Schedule 3 REGULATION & FREQUENCY RESPONSE SERVICE

The services provided under Schedule 3 are related to the continuous balancing of resources, either generation or interchange, with load and to maintain scheduled interconnection frequency at sixty cycles-per-second (60Hz). This service is typically provided with on-line generation whose output can be raised or lowered through the use of automatic generating control (AGC) equipment. The transmission customer has the option to purchase this service from the transmission provider, self-supply, or make alternative comparable arrangements that satisfy the Schedule 3 obligation.

The rates for Schedule 3 service are derived based on the fixed production costs of the generating units that typically provide this service (e.g., those with AGC equipment installed). It is fairly common for the rates under Schedule 3 to be inclusive of the purchase obligation, unless specified otherwise.

Schedule 4 ENERGY IMBALANCE SERVICE

The services provided under Schedule 4 are to cover any differences that occur between the scheduled and actual delivery of energy to a load within a control area over a given hour. The transmission customer can satisfy its energy imbalance service obligation by either purchasing this service from the transmission provider or make alternative comparable arrangements. The transmission customer cannot be charged a penalty for either hourly energy imbalances under this Schedule 4 or a penalty for hourly generator imbalances under Schedule 9 for imbalances that occur during the same hour unless the imbalances aggravate rather than offset each other. Under an Energy Imbalance Market or an RTO/ISO energy market, this service is provided by the market and priced at the prevailing LMP. Outside of these organized markets, the cost is based on the incremental/decremental cost of the local transmission provider (and is usually quite punitive).

Schedule 5 OPERATING RESERVE-SPINNING RESERVE SERVICE

The reserve services support load in the control area and exports from the control area immediately in the event of a system contingency. This service may be provided by generating units that are on-line and loaded at less than maximum output and by non-generation resources capable of providing this service. The transmission customer has the option to purchase this service from the transmission provider, self-supply, or make alternative comparable arrangements.

The rates for Schedule 5 service are derived based on the fixed production costs of the generating units that typically provide this service, which would include those units that are on-line and loaded at less than maximum output. Normally, this would include those units that are installed with AGC equipment.

Schedule 6 OPERATING RESERVE-SUPPLEMENTAL RESERVE SERVICE

The reserve services support load in the control area and exports from the control area in the event of a system contingency. Unlike Schedule 5, it is not necessary for the service to be available immediately to serve load but rather within a short period of time. This service may be provided by generating units that are on-line but un-loaded, by quick-start generation or by interruptible load or other non-generation resources capable of providing this service. The transmission customer has the option to purchase this service from the transmission provider, self-supply, or make alternative comparable arrangements.
Schedule 9 GENERATOR IMBALANCE SERVICE
This service covers any differences that occur between the output of a generator located within the transmission provider’s control area and a delivery schedule from that generator to another control area or a load within the transmission provider’s control area over a given hour. The transmission customer can satisfy its generator imbalance service obligation by either purchasing this service from the transmission provider or make alternative comparable arrangements. And similar to Schedule 4, for generators operating in an Energy Imbalance Market or an RTO/ISO energy market, this service is provided by the market and priced at the applicable hourly LMP. Outside of these organized markets, the cost is based on the incremental/decremental cost of the local transmission provider (and is usually quite punitive).

It is worthwhile to understand how the local control area operator/transmission provider has calculated the cost of ancillary services, and if necessary, review and challenge those costs when they do not represent the actual cost incurred to provide the service. Just as important, is the ability for TDU’s with generation resources to self-supply/provide reactive power, regulation, spinning and supplemental reserve services. This creates considerable value for the TDU’s and results in lower overall power cost to the retail customer.

For more information or to comment on this article, contact:
Patrick Brin, Senior Project Consultant
GDS Associates, Inc. - Orlando, FL
407.563.4463 or patrick.brin@gdsassociates.com

© 2015 by GDS Associates, Inc. All rights reserved. 
TRANSACTIONS is a service of GDS Associates, Inc. a multi-service consulting and engineering firm formed in 1986.

For more information about GDS, our services, staff, and capabilities, please visit our website

www.gdsassociates.com
or call 770.425.8100