Impact of FERC Rule #755

Frequency Regulation Compensation in the Organized Wholesale Power Markets

Roger Clarke-Johnson[1], American Governor Company, Kirkland, WA

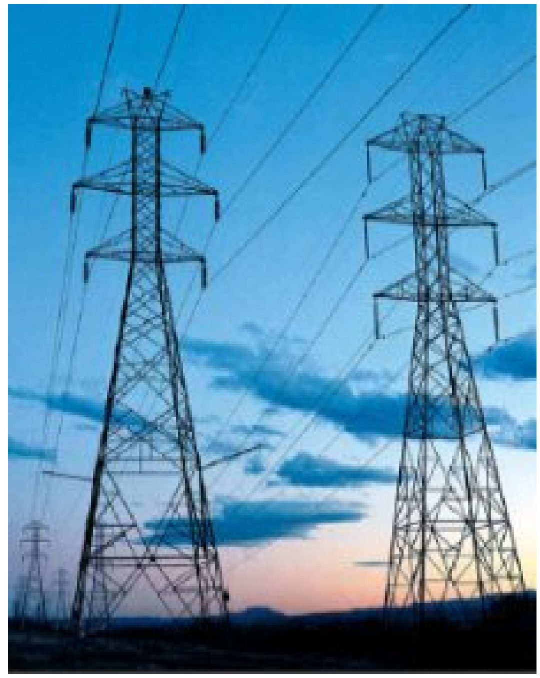
Abstract

Secondary frequency regulation service, also known as Automatic Generation Control (AGC), is one of the tools regional transmission organizations (RTOs) and independent system operators (ISOs) use to balance supply and demand to maintain reliable grid operations. On October 20, 2011, the Federal Energy Regulatory Commission (FERC) issued **Final Rule #755** regarding frequency regulation compensation in the organized wholesale markets. This final rule affects the compensation that energy providers receive for their services. In addition to the market for net energy consumption, there will be a market for secondary frequency regulation services. The final rule provides financial incentive for secondary frequency regulation performance and accuracy. The performance component rewards actual secondary frequency control contribution or "MW mileage." The accuracy component proposed by FERC is dependent upon how closely an energy provider follows the AGC signal.

This paper will analyze and summarize the impact of this FERC ruling on the hydro industry. Specifically, the hydro industry could realize new revenue streams by modifying the methods they use to control in hydro plants, some of which may actually be degrading grid stability and reliability, and the ruling may stimulate a discussion of how SCADA is used to control their powerplants. If the unintended consequence of this ruling is to minimize or negate the current contribution of hydroelectric plants to primary frequency control (governing with droop), recommendations to FERC may be suggested to avoid further degradation of the grid reliability due to reduced primary frequency control capability. Additionally, control system configurations that maximize revenues based on the new ruling along with their associated tradeoffs will be examined.

[1] rogercj@americangovernor.com

Brief History



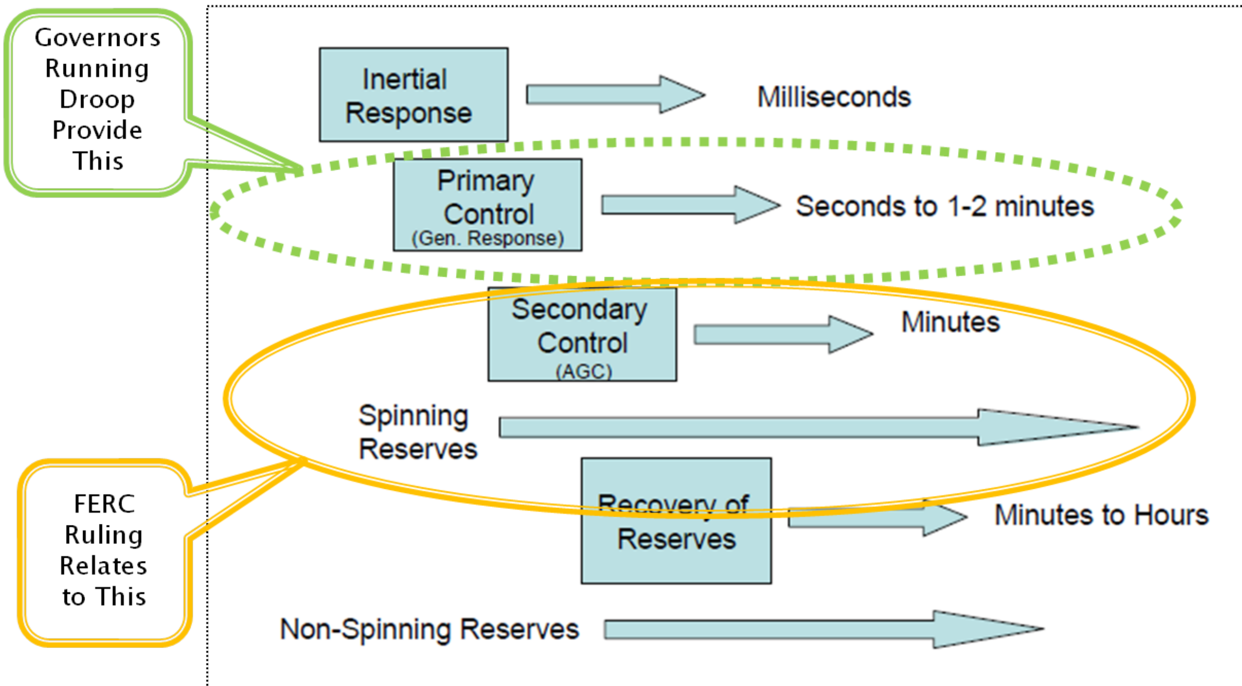
With the United States suffering several major regional brownouts and blackouts over the last fifteen years, not to mention concern over the threat of terrorist attacks on the utility grid, post 9/11, the Federal Energy Regulatory Commission (FERC) and its subsidiary agency, the National Electricity Reliability Council (NERC), have taken an increasingly vigorous and prominent role in studying, improving, and protecting the security and reliability of the nation's three electrical utility grids. Since the early 2000's, when the Western US faced frequent brownouts and an occasional blackout due to utility deregulation, a volatile spot market, and transmission bottlenecks, NERC began examining the ability of utility-scale generators and their Supervisory Control and Data Acquisition (SCADA) systems to effectively manage massive swings in load and generation that occur during large frequency excursions.

Since electricity storage is not yet available on a utility-grid scale (except for hydro pumped storage, available in some regions), load and generation must be *continuously* and *exactly* matched, otherwise unacceptable voltage and frequency swings will occur. In the post-event analysis of several regional blackouts over the last decade, NERC realized their current models for individual generator response were woefully out of date. They began mandating (instead of recommending) that all generators over 10MW be tested and the owners must submit detailed reports on the ability (or lack thereof) of each individual unit to automatically respond to frequency excursions. The performance metrics were (and are) used to update system models.

NERC also spearheaded a top-to-bottom evaluation of the assumptions used to model the electric grid in a macro sense, which includes transmission line capacity and voltage regulation aspects, since the assumptions being used by independent system operators (ISOs) and regional transmission organizations (RTOs) – themselves new creations, a result of utility deregulation - were obviously inadequate in predicting their ability of their network as a whole to successfully keep their regional grid up and running in the face of large (0.3Hz or greater; approximate) swings in frequency.

Also under scrutiny by NERC were plant-level and intertie-level protective relay settings and protocols the utilities and RTOs use to determine when they should separate from the larger grid during a large frequency or voltage excursion. Their analysis was driven in particular by the blackout in the Northeast US in 2003. After many months of study by independent organizations, it was determined that critical utility-scale feeder transmission lines and generators could have stemmed the spread of the outage but had instead tripped off prematurely - or were intentionally separated from the grid by human operators - causing the cascading blackout to worsen.

While NERC studied, reviewed and mandated, FERC focused on the other side of the equation: how should utilities be properly compensated when they help improve grid reliability? With grid frequency response capability declining over the past decade in all areas of the US, it became apparent that new forms of generation were not helping increase grid reliability, but were actually diminishing it. So, in October 2011 FERC passed a Final Rule #755 that described the benefits of "secondary frequency regulation" and recommended new methods to financially compensate those utilities who provide this important service.



In short: the FERC ruling says that if individual generators are demonstrably and actively helping stabilize grid frequency, they should be rewarded financially. Conversely, if individual generators *cannot* or *do not* (due either to their current method of operation, pollution constraints, thermodynamic constraints, or other issues) actively respond to grid frequency excursions, they should only be paid for the real power generated *and nothing more*.

FERC Final Rule #755: What It Says

> "Today, frequency regulation is largely provided by generators (e.g., water, steam and combustion turbines) that are specially equipped for this purpose."

> ***Translation: Any unit that is operating with Droop*** *is providing frequency regulation. As has been shown (footnote) this primary frequency regulation service is provided mostly by hydro and some Load Following gas turbine plants.* ***All so-called Base Load powerplants*** *(large mainline steam turbines, peaking aeroderivative gas turbines, combined-cycle and nuclear plants)* ***provide little to no frequency support!*** *Likewise, Must-Take renewable generation resources like solar and wind currently offer little to no frequency support.*
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> "RTOs and ISOs deploy a variety of resources to meet frequency regulation needs; these resources differ in both their ramping ability, which is their ability to **increase or decrease** their provision of **frequency regulation** service, and the **accuracy** with which they can respond to the system operator's dispatch signal."
>
> "Specifically, current [monetary] compensation methods for regulation service in RTO and ISO markets fail to acknowledge the inherently **greater amount of frequency regulation service** being provided by **faster-ramping resources**. In addition, certain practices of some RTOs and ISOs result in economically inefficient economic dispatch of frequency regulation resources."

Primary vs. Secondary Frequency Response

It is important to distinguish between primary and secondary frequency response. While the FERC ruling applies *exclusively* to secondary frequency response and the utility company's compensation for providing it, the ruling does also recognize and define primary frequency response:

> "When dispatched generation does **not** equal actual load plus losses ***on a moment-by-moment basis***, the imbalance will cause the grid's frequency to deviate."

As shown in the chart on page 1, primary frequency response is the initial, automatic response of all generators that are running in Droop. As has been shown (footnote), this immediate initial response provides the necessary correction to capture and reverse the deviation in frequency. Secondary response follows in the seconds and minutes following this initial, automatic correction:

> "**Frequency Regulation Service** [as defined in this FERC ruling] is the injection or withdrawal of real power by **facilities capable of responding appropriately to a** ***transmission system operator's*** [italics added] **automatic generator control (AGC) signal**."

It is this secondary response that shepherds the grid frequency back to the desired 60.00Hz. But, it was the initial primary response from participating generators that enabled the grid to 'turn the corner' on the frequency deviation.

“The system operator calibrates the AGC signal sent to frequency regulation resources to respond to **actual** and **anticipated** frequency deviations or interchange power imbalance, both measured by area control error (ACE).”

FERC Final Rule #755: What It Means

> “Specifically, this Final Rule requires RTOs and ISOs to compensate frequency regulation resources based on the actual service provided, including a capacity payment that includes the marginal unit’s opportunity costs and a payment for performance that reflects the quantity of frequency regulation service provided by a resource when the resource is accurately following the dispatch signal.”
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> “In this [ruling], the ability to provide more accurate frequency regulation service means to follow the system operator’s dispatch signal more closely ... It is possible that existing market participants would offer faster ramping capabilities to the system operator in response to a pricing scheme that recognized such service.”

Thus, the FERC has codified its desire that ISO’s and/or RTOs should develop and roll out new electricity pricing models and protocols to appropriately compensate utilities that provide Ancillary Services. It is now up to those System Operators and Transmission organizations to determine what makes sense for them, in their particular regions and territories.

It should be noted that, in addition to the Ancillary Services described and affected by this ruling, that Hydro generating units also provide the most ***primary frequency control*** response in the organized wholesale power market[1].

FERC Final Rule #755: What Happens Next?

As a federal agency, FERC has the authority and responsibility to *regulate* energy markets, but since electricity markets nationwide are not under centralized control, the FERC does *not* have the ability to *impose* specific compensation *mechanisms* upon individual power markets. Even so, FERC Rule #755 *does* provide a detailed description of new ancillary market compensation *methods* that it says *must be* developed and implemented by participants in individual markets:

“Specifically, this Final Rule requires RTOs and ISOs to compensate frequency regulation resources based on the actual service provided, including a ***capacity payment*** that includes the marginal unit’s opportunity costs and a ***payment for performance*** that reflects the quantity of frequency regulation service provided.” [Emphasis added]

Regarding equitable distribution of payments for Ancillary Services, the FERC also found that:

> "…[the current] compensation method does not acknowledge the greater amount of frequency regulation service being provided by ***faster-ramping resources***.…Slower, larger resources are being given a compensatory advantage for their size [capacity] while faster, smaller resources do not similarly receive compensation for the ramping speed and actual service provided.
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> "…[future rules for] payments [should also] include consideration for ***capacity set aside*** to provide (these services) as well as some of the following: the ***net energy*** that the resource injects into the system; ***accurately following*** the RTO's or ISO's dispatch signal; and the ***absolute*** (rather than net) ***amount of energy injected <u>or withdrawn</u>***." [Emphasis added]
>
> "These payments are intended to cover the range of costs incurred in providing Frequency Regulation Service, e.g., operation and maintenance costs, and loss of potential revenue from foregone sales of electricity."

Thus, the FERC has laid the official groundwork for utilities, Regional Transmission Operators and Independent System Operators to develop their own financial compensation packages and their own specific reward/penalty provisions.

Comments Prior To Final FERC Ruling

Many organizations commented on the FERC's Notice of Proposed Rulemaking (NOPR), and some of these comments were included in the published Final Rule. Many expressed support for the proposed Ancillary Services payments, while others thought the ruling would have no effect:

- "**Alcoa** states that compensating for the amount of movement (will create) strong market signals, because it ensures that those resources that are performing more work to correct system deviations are rewarded more."
- "**Beacon** contends that, currently, all resources (except in ISO-NE), regardless of how frequently they are deployed or how much of the ACE correction they provide, are paid the same price per MW for their capacity offered."
- "**PJM** states that it strongly supports a performance-based methodology. PJM claims that a performance payment provides an appropriate incentive to provide high quality regulation service by tying a portion of the total compensation to a resource's performance. In addition, PJM asserts that a performance payment will ensure resources provide accurate responses to control signals, in contrast with the current structure that provides no incentive to perform above a minimum threshold."

- "**EEI** contends that the Commission has not shown that changing the compensation mechanism to increase compensation for faster ramping resources will result in enhanced reliability … that the Commission is looking at only one of the three elements of frequency response (inertial response and governor response being the others) and in doing so has failed to provide the necessary technical basis to demonstrate that its assumptions that resources providing frequency regulation are more valuable than resources providing the other services…"
- "**NGSA** contends that there is a direct interrelationship between primary and secondary frequency control, and compensation for frequency regulation cannot be considered in isolation."
- "A **California Energy Commission** study showed that 'on an incremental basis, storage can be up to two to three times as effective as adding a combustion turbine to the system for regulation purposes.' "
- "**PJM** also argues the importance of procuring a mix of frequency regulation resources, some of which will have the ability to sustainably maintain their response."

It should be noted that among frequency-responsive sources of generation hydro is one of the very few generation resources that can **sustain its primary response for long periods of time**, especially compared to Load Following gas turbines and the relatively small energy storage systems available to you utilities today. These currently include storage batteries (large fields of theme) and Compressed Air Energy Storage (CAES). Further, what is unique about hydroelectric energy storage, there is **no efficiency loss whatsoever** in storing energy behind a hydroelectric dam, rather than generating with it.

Grid Reliability In the News

The topic of grid stability and the ability of the current grid to support future energy demands is the subject of conversation and articles in a variety of national and local publications, from energy trade journals to local newspapers. Whether you are a generator of power or simply the purchaser of a new electric car, the assumption of continuous availability of cheap electricity from a stable and reliable grid including the vital "Last Mile" of electricity distribution networks is taken as a given, but this assumption does not always hold true (as exemplified by the electricity shortages experienced in the Northeast US due to unseasonably hot weather in June 2012).

Whenever this assumption is cast into doubt, the concern and tension can be palpable. One utility observer quipped: "All we need are a few good blackouts to once again jump-start the public's interest in hearing what utilities need to spend to fortify the grid." A couple recent, articles gleaned from magazine publications and website postings touch on the topic of future grid demands and the effects of consumer choices in how they electricity is consumed.

This recent article[3]: **"Can Infrastructure Support EV Demands?"** posted by Jennifer Van Burkleo on **Electric Light & Power** magazine's website discusses the potential impacts on the grid of increased all-electric vehicle usage:

> ***"Grid Overload?***
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> *As of press time, a gallon of gas cost more than $4 in seven states: Alaska, California, Connecticut, Hawaii, New York, Oregon and Washington, according to AAA's Daily Fuel Gauge Report. The average cost to fill up an EV is less than $1 per gallon of gasoline equivalent, Gross said. Some people suspect that saving the equivalent of more than $3 per gallon might lure drivers to switch to EVs. That wave of EVs plugged into the grid, critics say, could overload the grid. Gross said the chances of that happening are very unlikely.*
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> *"If you took 10 million EVs and put them on the road, that represents less than a 1 percent increase of electricity depending on the grid," Gross said. EVs probably would charge overnight when electricity demand is low, she said.*
>
> *"Utilities' motto is to serve to the demands," she said, "so they overbuild the capacity on the grids. They design and plan for them to be over utilized, so we won't need new grids for a very long time, if ever."*
>
> *If there were a power shortage, EVs plugged into the grid could sell electricity back to the grid using smart meter technology. If several EVs charge simultaneously on the same transformer the transformer could burn out, Lefevre said.*
>
> *"Utilities see the smart grid as a likely solution to this concern," he said. "The smart grid can sense the load on the transformer and can take actions to relieve the load by changing the vehicle charging."*

Although EVs put out zero emissions, electricity generation sources differ regionally. An EV might be best for the environment in one state, but not in all states, said Schneider Electric's Davis. "Until we shift much more of our electricity generation to lower-carbon alternatives, in many states, efficient gasoline cars will be the best way to minimize the carbon footprint of daily driving," he said. In many respects, EVs are similar to the adoption of residential central air conditioning, he said.

"Those compressors were big draws, but the grid kept up and flourished," Davis said. "As long as EV adoption is a gradually building trend, many areas can adapt as-is, or with relatively minor upgrades to last-mile infrastructure like transformers."

Utilities and Regulators

When companies determine whether the infrastructure can withstand the demand, then they must go to their PUCs. Andy Roehr, managing director at PwC, said regulators have their work cut out for them because technology moves faster than law.

"It takes years for all parties to be on the same page," Roehr said. "We are hoping the problem does not go beyond the length it takes to solve it. We have some challenges bringing everyone together on a timeline to meet everyone's needs."

PUC regulations could stunt EV growth. Michigan and California PUCs have introduced time-of-use (TOU) rates in effort to balance utility and consumer interests. Utilities get more involved when TOU rates are involved, Roehr said. In states and regions where electricity costs more, consumers might take advantage of TOU rates and charge EVs overnight.

Engaging customers before introducing new technologies reduces the number of consumers against the technological change, Roehr said. Inevitably, recycling batteries will become an issue. "Battery disposals may force batteries into forced retirements to recycle," he said. "You can't take these batteries down to the junkyard--it would be very toxic. We need to build the infrastructure to charge and retire batteries in an environmentally and economically responsible way." Faster chargers will be introduced, and those might cause more stress to the infrastructure, Schneider Electric's Davis said. "Portions of the current grid would be upgraded, but there is no need for a new grid to for this purpose," he said.

[3] *Full article available at http://www.elp.com/index/display/article-display/3796359524/articles/utility-automation-engineering-td/volume-17/issue-6/features/can-infrastructure-support-ev-demands.html?utm_source=E-News+from+GreenBiz&utm_campaign=6c00387193-VERGE-2012-06-20&utm_medium=email*)

Another article, **"Automated Demand Response [ADR] Shows Smart Grid Power in Volatile Energy Environmen**t," also available on **Electric Light & Power's** website[4], touches on the challenges currently faced by electric utilities as they attempt to roll-out their Smart Grid:

> *"Electricity providers are bombarded with challenges in maintaining grid stability and keeping the power supply consistent. Peak-load variability is on the rise, and once common solutions such as building more fossil fuel-fired peaking plants are no longer defaults for solving energy issues. Renewable energy sources introduce another challenge: balancing intermittency.*
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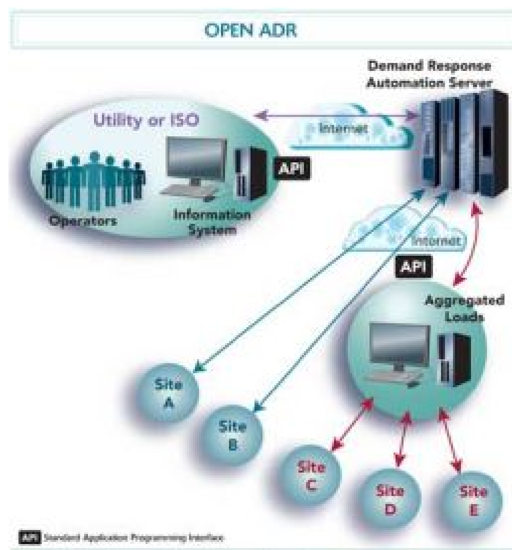
> *The smart grid's improved controls architecture and insight have ushered in alternatives for more dynamic energy management. These advancements have allowed utilities to increasingly leverage demanding resources for maintaining grid reliability. They have provided more opportunities to do so in a precise, mutually beneficial manner for all parties.*
>
> *A new demand-side paradigm exists. More utilities in the U.S. and across the globe are offering commercial, retail, institutional and industrial customers the option to join automated demand response (auto DR) programs. Auto DR programs automate a facility's response to energy prices and reliability signals so it can plan to reduce load during peak periods to trim costs and reduce grid strain. The programs provide direct, effective access to customers who use substantial amounts of electricity yet have been difficult to reach for load-balancing efforts. It also is one of the most cost-effective ways to meet demands…*
>
> *Auto DR programs are changing this load-shed equation and driving deeper, more successful results - the effects of the programs' repeatable, scalable and flexible load-reduction capabilities. These programs connect utilities with commercial and industrial customers--a customer segment with plentiful load-reduction potential, especially from an aggregation standpoint. This segment typically has the capacity to meet utilities' energy-shed needs--particularly when utilities need the additional capacity--and they can do so without negatively impacting business operations if they have enough notice. Commercial and industrial customers typically boast some of the foundational infrastructure on which utilities can build easily to further the critical, direct link with the facilities at the facility-equipment level.*
>
> *Using automated load-reduction technologies, auto DR programs remove the manual involvement required of customers, ensuring optimal, accurate, load-reduction measures occur in response to utility pricing signals. This flexible, open technology is paving the way for accessing hard-to-reach commercial and industrial customers, but it also is applicable to other customers, including residential and small commercial ones.*

Auto DR programs help participants save money or allow them better tariffs to take advantage of peak pricing periods. For utilities, auto DR benefits are numerous. Utilities gain direct insight into available customer loads during peak periods and a direct link to shed available loads in a precise, near-immediate way.

In addition to improving grid stability, auto DR programs can help utilities reduce carbon emissions by avoiding bringing idling peaking plants online. Shedding load instead of buying expensive power on the spot market saves money for utilities and their customers.

As states begin to issue regulatory goals, auto DR programs are meeting aggressive mandates, specifically renewable energy goals. In California, for example, 33 percent of public utilities' electric generation must come from renewable energy sources by 2020. As California works to meet this mandate and other states pursue similar goals, auto DR can help address accommodating peak variability changes produced by renewable generation, including solar and wind, to maintain grid reliability and balance intermittency…

Smart grid technology based on OpenADR 1.0 is interoperable and vendor-neutral, quelling concerns of stranded assets and future-proofing technology investments by auto DR program participants. This also provides a way for utilities to use auto DR software to send price and reliability signals over the Internet to participating customers using set OpenADR messages.



The OpenADR specification enables utilities to use demand response automation software to send price and reliability signals over the Internet to existing customers using a set OpenADR message. Image courtesy of Demand Response Research Center/Lawrence Berkeley National Laboratory.

These efforts led to the formation of the OpenADR Alliance, a group of utilities, companies and institutions including the Lawrence Berkeley National Laboratory, Southern California Edison, EnerNOC, Pacific Gas and Electric, Constellation Energy, Hawaiian Electric Co. and Honeywell. The alliance fosters the development, adoption and compliance of OpenADR to ensure the technical foundation for smart grid deployments using the specification, including auto DR programs…

Model of Grid Stability

Automated load-reduction methods enabled by the smart grid help utilities realize greater and more precise load control. With energy service providers that can provide engineering implementation services and engage a large customer base with significant load-control potential, utilities can use auto DR programs to monitor when and how electricity is used to maintain a more stable electric grid."

[4] *Full article available at http://www.elp.com/index/display/article-display/2301558781/articles/utility-automation-engineering-td/volume-17/issue-6/features/automated-demand-response-shows-smart-grid-power-in-volatile-energy-environment.html*

Conclusion

The electricity grid in the United States is a complex network of regional and national companies and regulatory organizations that, throughout the 20th century, did such an exemplary job of planning and expanding both generating and transmission resources, most end-user customers took the availability of cheap and reliable electricity for granted. That apathy tends to change to interest when brownouts and blackouts occur, and the attitudes of end-users will surely change again when the next blackout - or rate hike - occurs.

Given the tortured and sometimes conflicting logic of myriad state, regional and federal regulations; stakeholder special interests; and assorted state, regional and national governmental bureaucracies; it is difficult to predict what impact this recent FERC ruling will have on the actions and investments made by US electric utilities to enhance the reliability of the US electricity grid. What is clear, however, is that eventually *all* electric utilities will get paid for providing "ancillary services" such as secondary frequency regulation.

FERC Ruling #755 is a very positive development because it identifies current failings in the way some utilities are compensated for ancillary services they are already providing for free, and it provides a necessary framework for designing new compensation mechanisms that reward electric utilities that provide necessary – and sometimes critical – frequency regulation services, while penalizing (by withholding additional payments) those utilities who do not.

References

1. FEDERAL ENERGY REGULATORY COMMISSION, UNITED STATES OF AMERICA, 137 FERC ¶ 61,064, 18 CFR Part 35, Docket Nos. RM11-7-000 and AD10-11-000; Order No. 755: Frequency Regulation Compensation in the Organized Wholesale Power Markets (Issued October 20, 2011)
2. "The Impact of Hydroelectric Power and Other Forms of Generation on Grid Frequency Stability for the WECC Region," Hydrovision 2011 Technical Paper, July 2011.
3. "Can Infrastructure Support EV Demands?" Electric Light & Power, Jennifer Van Burkleo, June 2012.
4. "Automated Demand Response Shows Smart Grid Power in Volatile Energy Environment," Electric Light & Power, Jack Rosenthal and David Wylie, June 2012.

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Author Biography

Roger Clarke-Johnson is currently Sales and Marketing Manager for American Governor Company. (www.americangovernor.com) Roger has 25 years of experience in hydro governing systems, starting as an Application Engineer for Digitek way back in 1987. His prior positions include Controls Sales Manager for Woodward Governor Company and Regional Manager for Governor and Excitation System Sales for the Power Systems division of General Electric. Before coming into the hydroelectric industry, Roger had six years of experience working in the fledging Wind Turbine industry, first at the Boeing Company in Seattle, WA and later with Flowind in Pleasanton, CA. Roger graduated with honors from the University of Illinois, Urbana-Champaign, IL in 1981.