Volt/VAR Optimization Improves Grid Efficiency

Introduction

Traditional Voltage/ VAR management[1] technologies have been used by the power industry for over 30 years to reduce electric line losses and increase grid efficiency. Today those technologies have advanced to include Volt/Volt-Ampere Reactive Optimization (VVO) sensors, equipment and software capable of reducing overall distribution line losses by 2%–5% through tight control of voltage and current fluctuations.

Despite their ability to significantly improve power quality, lower line losses and reduce peak demand compared to traditional methods, VVO systems have not been widely deployed in the United States because traditional utility fee structures fail to provide revenue recovery or ROI to pay for the needed investments.

In November 2012, the National Association of Regulatory Utility Commissioners, representing the public utility commissions of all fifty states and our territories, recognized the need for change through its resolution of support for the adoption and rapid deployment of voltage optimization technologies, stating:

> *"(NARUC) encourages State public service commissions to evaluate the energy efficiency and demand reduction opportunities that can be achieved with the deployment of Volt-Var Optimization (VVO) technologies…and encourages State public service commissions to consider appropriate regulatory cost recovery mechanisms."* [2]

NEMA supports the NARUC position and further recognizes an appropriate role for federal support in expediting state adoption of VVO technologies. Federal legislation to improve energy efficiency and advance the electric grid must include incentives to encourage the deployment of voltage management technology and should include incentives for the adoption of State Energy Efficiency Resource Standards, electric utility rate incentives, and/or the establishment of a grid optimization fund to finance necessary upgrades.

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[1] VAR or Volt-Amphere Reactive is a unit used to measure reactive power in alternating current

[2] http://www.naruc.org/Resolutions/Resolution%20Supporting%20the%20Rapid%20Deployment%20of%20Voltage%20Optimization%20Technologies.pdf

Background

The concept of Voltage/VAR management or control is essential to electrical utilities' ability to deliver power within appropriate voltage limits so that consumers' equipment operates properly, and to deliver power at an optimal power factor to minimize losses. These concepts are affected by a variety of factors throughout the distribution network including: substation bus voltages; length of feeders; conductor sizing; type, size, and location of different loads (resistive, capacitive, inductive, or a combination of these); and the type, size, and location of distributed energy resources (photovoltaics, distributed wind, various storage technologies, etc.); among others.

The complexity and dynamic nature of these characteristics make the task of managing electrical distribution networks challenging. While voltage regulation and VAR regulation are often referenced in combination (i.e. Volt/VAR control), they are perhaps easier to understand if described as two separate, but interrelated concepts.

Voltage Regulation. Feeder voltage regulation refers to the management of voltages on a feeder with varying load conditions. Regardless of nominal operating voltage, a utility distribution system is designed to deliver power to consumers within a predefined voltage range. Under normal conditions, the service and utilization voltages must remain within ANSI standard C84.1-2011 limits, defined as Range A. On a 120V base, this service range is defined as 114–126V and utilization range is 110-126V. During high load conditions, the source voltage at the substation is at the higher end of this range and the service voltages at the end of the feeder are at the lower end of the range.

VAR Regulation. Nearly all power system loads require a combination of real power (watts) and reactive power (VARs). Real power must be supplied by a remote generator while reactive power can be supplied either by a remote generator or a local VAR supply, such as a capacitor. Delivery of reactive power from a remote VAR supply results in additional feeder voltage drop and losses due to increased current flow, so utilities prefer to deliver reactive power from a local source. Since demand for reactive power is higher during heavy load conditions than light load conditions, VAR supply on a distribution feeder is regulated or controlled by switching capacitors on during periods of high demand and off during periods of low demand. As with voltage control, there are both feeder design considerations (to minimize capital costs) and operating considerations.

Volt/VAR Regulation. Supplying VARs when and where demanded is inherent to operating an electric power system. But the flow of reactive power affects power system voltages just as the flow of real power does. The effects of real power flow nearly always have negative effects on voltage while the effects of reactive power flows are sometimes positive and sometimes negative. Experience has proven that overall costs and performance of operating a power system can be best managed if voltage control and reactive power control are well integrated.

A number of technologies have been employed by utility companies to monitor and adjust voltage and/or VAR levels on their electrical networks. In substations, these include capacitor banks, voltage regulators and power transformers with on-load tap changers (OLTC). Of course by being located in the substation, these devices manipulate electrical parameters at the substation bus level. While they take into account down line feeder conditions, they are utilized primarily for gross adjustments and were designed initially for radial distribution networks. Down-line feeder technologies including fixed and switched capacitor banks and voltage regulators are also utilized to help adjust system parameters along the length of a feeder.

With the development of microprocessor-based controls and computing platforms, pervasive, high performance communications technologies, widely deployed sensor technology including AMI systems and advanced software algorithms, it is now possible to coordinate these devices to optimize the broader electrical system at the feeder, substation or utility level with VVO systems. With these integrated systems in place, utilities can optimize voltage profiles and VAR flow to achieve a variety of objectives, including: reducing peak demand, targeting power factor levels to minimize energy losses, or implementing Conservation Voltage Reduction (CVR). CVR controls feeder and substation equipment to lower distribution line voltage within approved standard ranges. The result is a significant reduction of losses and energy demand. They can also change target objectives at different times of the day/week/month/year to meet performance goals.

Benefits

There are a number of benefits associated with implementing VVO technologies. For utility operations, VVO solutions provide a higher level of visibility into system operating parameters and a greater degree of control to optimize energy efficient and reliable electricity delivery. VVO technologies help utilities move from flying blind to operating with end-to-end instrumentation on feeders and automated optimization. Utilities are facing a dynamic operating landscape, a landscape that wasn't envisioned when most electrical networks were designed. The increasing penetration of intermittent renewable generation sources, the increasing diversity and variability of loads are driving this volatility. Utilities are also running closer to the operating limits of these systems than ever before, making the ability to optimize within operating parameters extremely important.

In the case of a vertically integrated utility, being able to optimize a power factor means that the utility has to generate less power to satisfy the demand of its customers. In simple terms, certain power factor conditions require utilities to generate more real power than is actually needed by its consumers. This excess real power is wasted in the form of thermal losses. The ability to optimize power factor is a key driver in a utility's ability to minimize losses. This particular benefit also serves the environment; if a utility has to generate less power to serve the same demand then in turn they burn less coal or natural gas and therefore emit less CO^2. Similarly, utilities that purchase power from transmission companies or independent power producers usually have contractual, financial incentives including steep penalties for operating outside of specified power factor limits.

Strategies such as Conservation Voltage Reduction (CVR) have numerous potential benefits. This type of VVO solution can be used to flatten voltage profiles and then lower overall system voltage while staying within the specified ANSI voltage limits. In short, doing this reduces overall system demand by a factor of 0.7-1.0% for every 1% reduction in voltage. From a consumer perspective, this reduces the energy they consume. From a utility perspective it reduces the amount of power they need to generate or purchase from a generator. There is a cost benefit associated with reduced operating costs, but to the extent these strategies can be implemented to defer investment in new generation capacity or to address reduced capacity due to old generating assets being taken offline, the benefits can be enormous especially when load growth is small.

Examples of results from utility studies and pilot projects on CVR include:

- A 1987 study at Northeast Utilities showed a 1% energy savings for each 1% voltage reduction.
- A distribution efficiency initiative was commenced in 2003 by the Northwest Energy Efficiency Alliance and completed in 2005 - 13 utilities showed an average of 0.8% energy savings for each 1% voltage reduction.
- Results of a recent EPRI study of 6 distribution feeders over a one year period showed energy savings ranging from 0.66% to 0.92% for each 1% voltage reduction.
- Recent pilot studies conducted by Dominion Virginia Power showed a 0.8% energy savings for each 1% voltage reduction study.

Challenges

There are several challenges facing utilities who are interested in deploying VVO technologies, which range from financial hurdles to technical hurdles. Each must be considered in determining how to best fund these deployments and maintain and manage them long term.

The primary technical hurdles typically involve how best to deploy the solution across the distribution feeders. The main hurdles determining the communication technology that can best fit the deployment needs as well as the optimal sensing solutions to provide real-time voltage measurements to the VVO system. Utilities have used communication systems ranging from public wireless technologies, such as 4G/3G, to private wireless mesh technologies, including Advanced Metering Infrastructure (AMI) networks. In terms of the sensing solutions, they have used devices such as stand-alone voltage and current sensors to AMI meters as well as integrated sensing in devices such as capacitor controls. Tied to these technical hurdles is the cost to deploy these communications and sensor technologies along with the VVO system.

The financial hurdles to the deployment of VVO technologies are particularly acute for regulated investor-owned utilities operating as transmission and distribution wires companies. Utilities which are paid for the volume of electricity delivered have limited incentive to implement energy savings technologies. Revenue-reducing technologies like VVO face greater obstacles due to the rate structures currently in place which were applied to recover investment and upgrade costs based on kWhs delivered. The long term benefits enabled by VVO, such as reduced generation requirements through deferral of new infrastructure, the ability to burn fewer fossil fuels, and the improvement to both system operations and the quality of power delivered to consumers, fail to offset the revenue impact of the rate structure for wires companies. The benefits do not compete with the immediate need for investor returns and impact the returns of previous investments without some financial recovery incentive for the utility.

VVO technologies also suffer when compared to utility and regulatory funding for energy efficiency programs. For most utilities seeking to enable energy efficiency, there is typically ample funding for programs such as customer demand response and load control, which require the utility to install controls within the customer premise to enable demand and energy reduction. However, these same programs fail to account for the ability of VVO to provide similar results for demand and energy reduction without the need for customer involvement. All of the energy efficiency technologies should therefore be treated equally in terms of their ability to enable energy efficiency through the electric distribution system.

There are similar financial hurdles for utilities that buy power from entities such as regional generation and transmission companies. These utilities typically deploy VVO for peak demand reduction as they are charged a higher rate from the G&T for their monthly peak demand. However, they usually will not use the VVO technology during off peak periods as it decreases their revenue, which is needed to offset their traditional operational costs.

Conclusion

Volt/VAR Optimization has been successfully used to increase power system efficiency by all types of utilities for many years. This record of success and today's smart grid advances have led industry experts like NARUC to recognize the significant energy savings and reliability benefits available through use of VVO, and the need for incentives to drive their adoption.

Absent new rate structures or financial compensation to address the cost of deploying VVO technologies, these valuable tools will languish. Therefore, NEMA urges policymakers to support the widespread deployment of these important control systems through appropriate investment incentives, recovery rate structures and tax policy.

Case Studies

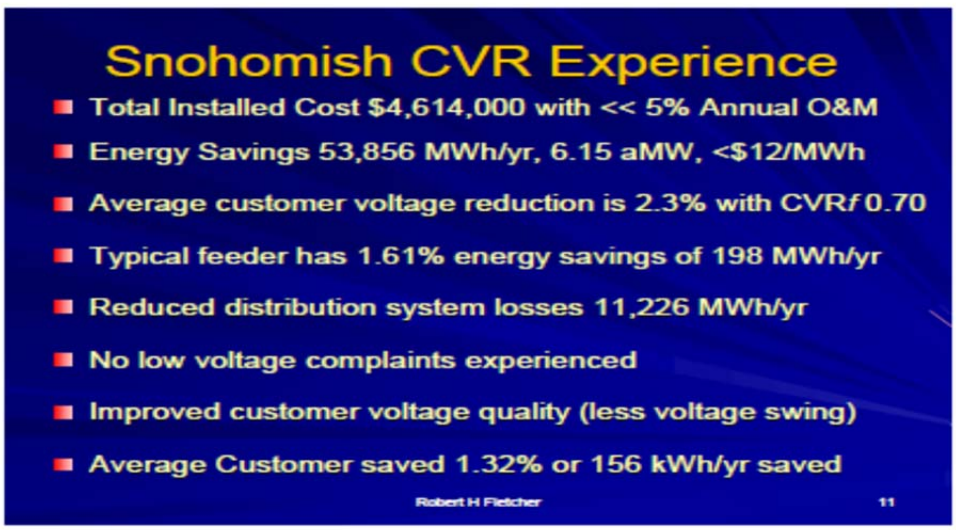
What follows are some case studies that provide compelling cost/benefit examples of voltage management implementation.

- **The Snohomish County PUD** installed a Conservation Voltage Reduction system to improve system throughput and improve power quality. Their investment of under $5 million has resulted in energy savings of 53,856 MWh/yr, including reduced distribution system losses by 11,226 MWh/yr while providing better voltage quality (less voltage swing) to end-use customers.

- **The Northwest Energy Efficiency Alliance** studied 13 utilities for the impact of lower voltage on consumers. Their work showed voltage reductions of 2.5% resulted in energy savings of 2.07% without impact on consumer power quality.

- **The Clinton Utilities Board** is using state-of-the-art voltage regulation technologies to power 3,000 homes solely through energy savings. Utilizing Dispatchable Voltage Regulation to safely and automatically adjust end-use voltages to meet peak demand needs, Clinton has harnessed a virtual power plant by capturing otherwise lost energy to meet service needs.

- **Oklahoma Gas & Electric** (OG&E) is in the process of implementing volt/VAR optimization (VVO) across 400 feeder circuits to achieve a 75-megawatt load reduction within the next eight years. Advanced model-based VVO allows OG&E to maximize the performance and reliability of its distribution systems while significantly reducing peak demand, minimizing power losses and lowering overall operating costs.



Utility Energy Efficiency Summit, March 17-18, 2009, Robert Fletcher, PHD, P.E.[3]

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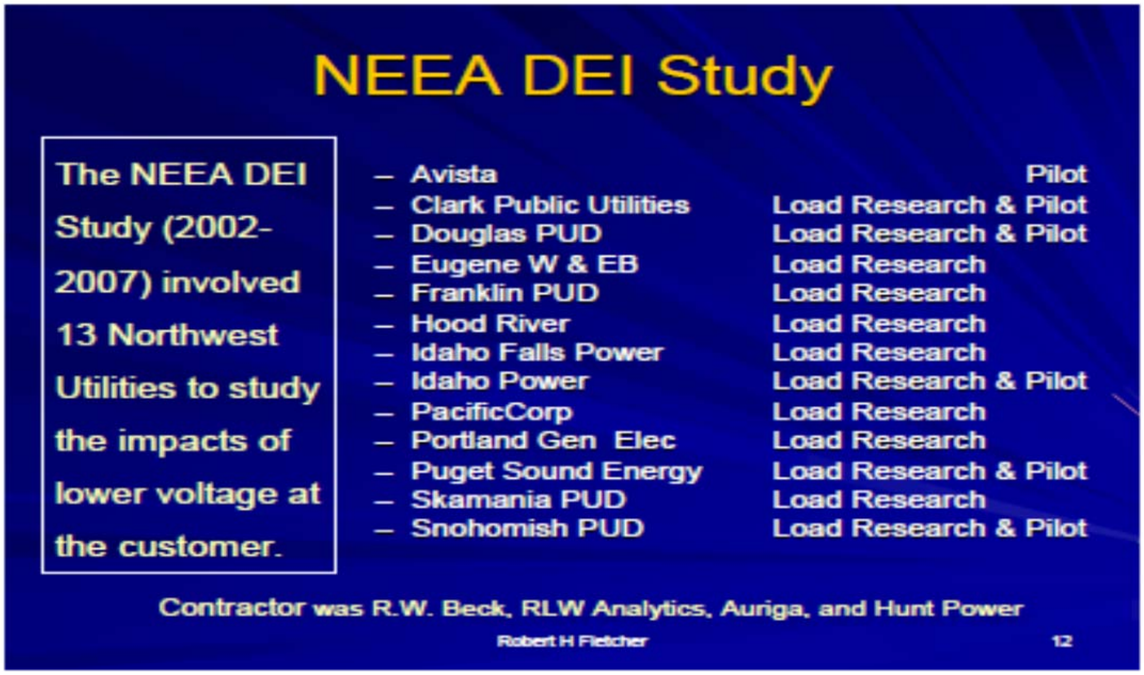
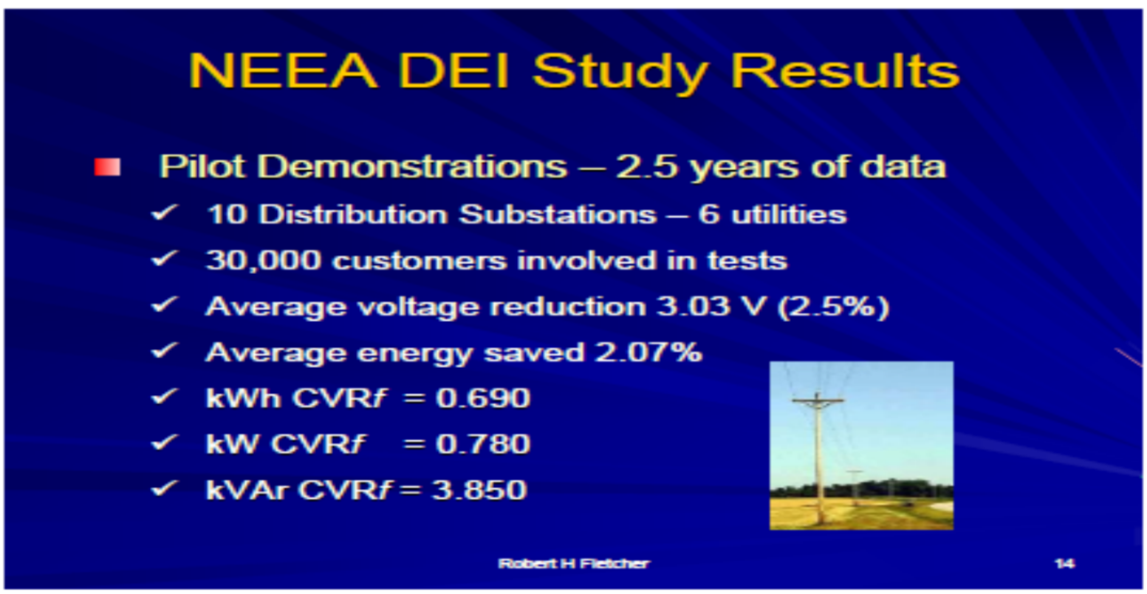
3 http://www.bpa.gov/Energy/N/Utilities_Sharing_EE/Utility_Summit/Workshop2009/pdf/BobFletcherSnohomishPUD.pdf





Utility Energy Efficiency Summit, March 17-18, 2009, Robert Fletcher, PHD, P.E.[4]

[4] *Id.*

Clinton Utilities Board Partners with TVA on new Energy Saving Program[5]
Oct. 22, 2012

Imagine a power plant that generates zero emissions, power for 3,000 homes, and saves ratepayers hundreds of thousands of dollars. And by the way … this power plant is *invisible.* Clinton Utilities Board has created exactly that. They're one of the first power companies in the Tennessee Valley Authority's seven-state service region to build their own "virtual power plant." Instead of bricks, mortar and generators, CUB is using state-of-the-art technology called Dispatchable Voltage Regulation which automatically adjusts end-use voltages across their service area.

The virtual power plant enables CUB to make carefully monitored voltage reductions in its distribution system when requested by TVA. When CUB activates its demand reduction technology, less power is used throughout CUB's service territory, enabling TVA to use that power to supply other customers. "We have always strived to use cutting-edge technology and forward-thinking to design and implement projects such as this demand reduction technology. Said Greg Fay, CUB General Manager. "Our ability to leverage this technology has reduced our wholesale power costs, thereby saving our local ratepayers over $800,000 to date and will help lower utility bills throughout the TVA service area."

"CUB is pleased to partner with TVA in this pilot effort to reduce peak power demands" said Ernie Bowles, CUB's Assistant General Manager. "When we get a request from TVA for demand reduction, it occurs within seconds and its effects are invisible to our customers. This will help lower utility bills throughout the TVA service area." Earlier this summer, when temperatures topped 100 degrees across the Tennessee Valley, CUB used its virtual power plant to help TVA supply power to the region. TVA has asked CUB to engage their Virtual Power Plant on five different dates this summer. Each time, the project has been successful in utilizing its technology to aid TVA in meeting the power requirements of the valley.
"We applaud CUB for being the first local power company in the valley to join us in this new initiative," said John G. Trawick, TVA's senior vice president of Power Supply and Fuels. "Utilities have known for some time that voltage reduction held great promise for reducing peak power demand and lowering emissions, but until recently the technology was out of reach and demand and energy wholesale rates were not in place to use the technology effectively. CUB is helping us lower the cost of providing electricity at those times when power usage and costs are the highest." The virtual power plant is headquartered in a brand new high-tech control room, with big screen monitors showing real-time data from smart meters across the entire service area. It's all part of a TVA Smart Grid Pilot program to cut energy use during peak periods.

Clinton Utilities Board was founded in 1939. When the town acquired the system, it served only 1,877 customers. Today CUB distributes electric service to about 30,000 customers in six counties (Anderson, Campbell, Knox, Morgan, Roane and Union) and four municipalities (Clinton, Lake City, Norris and Oliver Springs). CUB purchases wholesale power from TVA. CUB provides the necessary facilities to distribute electric service over approximately 1,400 miles of high voltage circuitry to our customers.

The Tennessee Valley Authority, a corporation owned by the U.S. government, provides electricity for business customers and distribution utilities that serve 9 million people in parts of seven southeastern states at prices below the national average. TVA, which receives no taxpayer money and makes no profits, also provides flood control, navigation and land management for the Tennessee River system and assists utilities and state and local governments with economic development.

[5] http://www.clintonutilities.com/TVA%20Press%20Release-CUB%20Virtual%20Power%20Plant.pdf

- Decoupling of sales from revenue and Revenue Recovery. The following example of Entergy's CVR installation shows the significance of this challenge.

Entergy
THE POWER OF PEOPLE®

Entergy Tests AMI Voltage Optimization

What else can the smart meters do?

Katherine Tweed: January 27, 2012

Many people working in smart grid argue that the smart meter, which got so much attention (and stimulus funds) in recent years, is just an endpoint. Real smart grid is on the grid itself, providing two-way communication and more efficient power flow across the distribution system.

But what if the meter can help with some of that? Following in the footsteps of Dominion Virginia Power, Entergy is using its Elster smart meter system to understand, and adjust, voltage conditions at the end of the line.

Entergy has been testing two residential feeders, one with about 70 meters on the end and the other with about 30. The utility is seeing a consistent 4 percent to 6 percent savings in energy consumed.

The project, which also involves ABB and Survalent Technology, will next move into a controlled pilot to figure out the business case to bring to the public utility commission. If all goes well, it could then be expanded to many feeders throughout Entergy's territory.

That's a big if, however. Voltage reduction seems like a win-win. A recent GTM Research report, Distribution Automation: 2012-2016: Technologies and Strategies for Grid Optimization, noted that "VVO is poised for an explosion of acceptance among utilities looking to reduce peak load and defer capital expenditures through CVR or increase control of voltage and reactive power levels on the distribution grid."

However, that's only if the utilities are incentivized to shave peak load through decoupling or other methods that ensure that the utility won't be losing money if they sell less power. "The challenge is to make sure we have the right regulatory recovery mechanism," said Paul D. Olivier, Director of Smart Grid at Entergy.

For investor-owned utilities that already have something in place that allows them to increase efficiency without sacrificing profits (or for Munis and Co-Ops, that are seeking the lowest rates for their customers), David Green of Elster argued that voltage conservation and transformer management using advanced metering can boost the business case by squeezing more value out of the system. "Beyond radial feeders, networked systems will also provide a quick payback for utilities interested in VVO, as they consist of shorter, heavily loaded lines," wrote Ben Kellison, author of GTM Research's latest DA report.

To reduce the voltage, Entergy is adjusting capacitor banks and adjusting setting for load tap changers at the substation. "Some of the secret sauce in the software is creating optimal settings so you're not creating feedback loops," said Olivier.

To support the findings of the Entergy pilot in Louisiana, Elster formed the Smart Grid Voltage Conservation Alliance in August 2011. If the pilot is successful, Elster hopes to expand it to other utilities. For now, the alliance is comprised of just the companies involved in the Entergy pilot -- hardly an industry consortium so far.

For ABB, which has a clear stake in conservation voltage reduction hardware, the project has allowed the company to learn more about voltage across the feeders and down the end point, according to Jon Rennie, vice president and general manager for ABB Distribution Components. Although metering can provide insight into what's happening down the feeder, it can't provide the switching that's needed back at the substation or on the line to reduce the voltage.

In Louisiana, Entergy is adjusting capacitor banks or adjusting settings for load tap changers at the substation to achieve the reduction. The hard part is finding just the right balance so that two devices aren't fighting each other to get the reduction, Olivier said.

But even more difficult than achieving the right balance using the AMI system and just the right devices is getting regulators on board. "Our challenge is to get CVR to be included in energy efficiency for recovering lost revenue," Olivier said. "The good news is, I don't think these are insurmountable hurdles."[6]

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6 Entergy Tests AMI Voltage Optimization Greentech Media.mht

NY utilities: Transmission solutions far less costly than repowering 2 plants
May 23, 2013 Thursday
SNL Power Daily with Market Report
Kerry Bleskan

Utilities that will be affected if two New York power plants are shut down permanently say transmission upgrades fix the problems more cheaply than repowering the units.

The coal-fired Dunkirk and Cayuga plants were slated to be closed and are currently running under agreements with National Grid USA and New York State Electric & Gas Corp. The New York Public Service Commission ordered the utilities to examine the relative costs and benefits of transmission solutions versus repowering the plants to run on natural gas. National Grid and NYSEG submitted their reports on May 17.

National Grid and the Dunkirk plant

The western New York system is vulnerable to low voltages during transmission outages with or without Dunkirk, National Grid said, but the problem is worse when Dunkirk is out. By National Grid's calculations, transmission solutions to maintaining reliability in southwestern New York state would be three to seven times less expensive than repowering the Dunkirk plant, which is owned by NRG Energy Inc. NRG submitted a plan in March to replace the existing 1950s-era Dunkirk units with a 440-MW combined cycle gas plant, online in 2017.

The report from National Grid, known legally in New York as Niagara Mohawk Power Corp., found a number factors to be equal between the generation and transmission options, including job creation and environmental and reliability benefits, so it based its recommendations on cost. "The company does not oppose generation repowering in principle; however, repowering at the Dunkirk facility is not in the best interest of customers," National Grid said. "In addition, repowering under the commercial structure proposed by NRG would shift significant risk back to customers and away from the competitive market."

National Grid evaluated NRG's repowering Option 1 as a new 422-MW combined cycle gas turbine located on the 230-kV network and online in 2017 plus refueling Dunkirk Unit 2 as a 75-MW gas unit on the 115-kV system, complete by 2015. Option 2 would add natural gas firing capability to Dunkirk units 2, 3 and 4 for 455 MW of generation capacity. Option 3 is 285 MW of new gas peaking units. Repowering Option 3 is insufficient to meet reliability needs, National Grid said, so it was dropped from consideration.

The $63 million transmission option includes a series of upgrades that would be in service by June 2015 and which would eliminate the need for the existing reliability agreement with the Dunkirk plant, and two longer-term reliability projects to be completed later, by 2018 at the latest.

The first repowering option created the most jobs during construction compared to the transmission option and the other repowering option. "However, the costs and resulting rate impacts of Repowering Option 1 would result in the highest number of job losses during the study period," National Grid said.

"Based on the analysis summarized in this report, the company recommends the commission support the transmission upgrades to address the reliability needs at the lowest overall cost, least risk to customers, and with minimum impact on competitive markets," National Grid said. "The regulated nature of the transmission upgrades also provides for greater transparency of and scrutiny over the investments that are being made for the benefit of customers."

National Grid estimated that transmission upgrades will cost customers about $10.5 million per year, a net present value of $70.5 million over the study period. Repowering Option 1 would cost $375 million over 10 years, and Option 2 would cost $218 million over 10 years. The projects' net costs in 2018 were redacted. Translating those numbers to delivery cost increases to customers, the transmission option would raise delivery costs by 0.5% for residential customers and 1.3% for the largest customers. The first repowering option would raise costs by 3.5% to 9.5%, and the second repowering option would raise costs by 5.3% to 13.9%, depending on customer class.

NYSEG on the Cayuga plan

Iberdrola SA subsidiary New York State Electric & Gas also recommended a transmission reinforcement solution over repowering, regarding Cayuga Operating Co. LLC's 309-MW, two-unit Cayuga coal plant, which dates from 1955.

NYSEG conducted reliability analyses of its system with a mothballed Cayuga plant and found issues would start cropping up at 65% of projected peak summer loads. The company has already proposed an Auburn-area transmission reinforcement of one new 14.5-mile, 115-kV line. Should the plant be retired permanently, NYSEG proposed to rebuild another 14.5-mile, 115-kV line, although a less expensive National Grid capacity-upgrade project will eliminate the same problems.

Cayuga presented NYSEG with four repowering options, each of which requires a new natural gas pipeline to the Cayuga Generating Facility site and relies on a levelized revenue stream from NYSEG customers over a certain, confidential number of years. Option 1 is a repowering of the two existing coal-fired boilers and would have a maximum output of 300 MW. Option 2 would achieve a similar maximum output, 294 MW, with three new simple-cycle combustion turbines.

Option 3, maximum output 300 MW, would repower Cayuga unit 2 with a combined-cycle turbine generator, a heat recovery steam generator and a condensing cycle steam turbine generator. Option 3 is described as a hybrid of Options 1 and 4, and additionally raises the possibility to fuel-switch Cayuga unit 1 to natural gas.

Option 4 uses the same combination of equipment as Option 3 but has a maximum output of 326 MW due to two new combined-cycle combustion turbine generator trains. Option 4 would provide the most flexibility and reliability, NYSEG summarized, "but at an added cost."

NYSEG said that the repowering options are riskier than transmission options in several different ways. Cayuga's proposal places the full market risk on NYSEG customers, the utility said, because NYSEG would make a fixed payment to Cayuga and the offsetting market price revenues will fluctuate.

Additionally, NYSEG was unable to duplicate Cayuga's forecasted level of revenues and worries that Cayuga may have overstated the revenue potential of a repowering option. "NYSEG is concerned about its customers assuming the market price risk associated with the Cayuga repowering option," the utility said. "If this market risk is removed and no market revenues are assumed, the transmission option is the least cost option."

NYSEG also argued that transmission options are better for the environment and for competitiveness in the electricity market. "By definition, Cayuga [out of merit] operation reduces economic efficiency and increases costs for customers in the sub-zone," NYSEG said.

Even if a generation option is chosen, NYSEG said, transmission planning for risk mitigation should continue until the generation is online, "given the uncertainty inherent in a generation option." The utility asked regulators to allow it to move ahead with planning and approvals in case a generation option falls through. "The company's customers cannot wait for three years for a repowering project to be completed, only to find out that Cayuga (or another developer) cannot or will not be able to bring on line the generation necessary for reliability," NYSEG said.

Details provided by Cayuga were redacted from NYSEG report, including the maximum heat rate and development timelines and cost recovery proposals for the several repowering options. "The recommendations are necessarily preliminary given the unverified nature of the information underlying the four repowering options proposed by Cayuga Operating Company LLC," NYSEG said, noting other future uncertainties including the price of natural gas.