

ALLIANCE RTO; GONE BUT NOT FORGOTTEN

The Alliance RTO was born in May 1999, when five electric utilities -- Virginia Power, American Electric Power (AEP), Consumers Energy, FirstEnergy, and Detroit Edison -- submitted a proposal to the Federal Energy Regulatory Commission (FERC) to form a for-profit independent regional transmission organization. "We have worked hard to develop a regional transmission organization that facilitates competition and provides flexibility for our participation in the future," said Robert E. Rigsby, Virginia Power president and chief operating officer, at the time the filing was made. "With this model, all electric suppliers would have equal, nondiscriminatory access to the electric power grid and to wholesale and retail customers. We think this is the best solution to promote fair and effective competition."

At the time, Alliance's concept of a for-profit RTO was viewed as groundbreaking. In fact by late 2000, Alliance has grown even more powerful as Dayton Power & Light, ComEd, Northern Indiana Public Service Co. (NIPSCO), and Illinois Power fled the Midwest ISO's non-profit structure for the Alliance. "Joining the Alliance RTO will provide us, and our customers, with better access to electric sup-

plies and offer the potential for cost savings as the industry continues to restructure," said Betsy Moler, senior vice president of Federal Government Affairs and Policy for Exelon Corporation, ComEd's parent.

Things looked to be going well when the Alliance RTO received initial approval from FERC on January 24, 2001. By August 2001, Alliance had selected National Grid as the managing member of the RTO. However, a change in FERC's position on RTOs, brought on by the ascendancy of Pat Wood as Chairman, proved deadly for Alliance as on December 20, 2001, FERC, in deciding whether to grant the Midwest ISO (MISO) status as an RTO, concluded that the MISO's RTO proposal more fully complied with the vision and requirements of Order No. 2000, in particular the requirement that an RTO be of sufficient scope. Therefore, FERC granted the MISO RTO status, and stated that MISO should serve as the foundation upon which a Midwest RTO should be built. FERC also concluded that the Alliance Companies, which had filed for approval as a separate RTO, lacked sufficient scope to exist as a stand-alone RTO.

In March 2002, the Alliance companies and National Grid filed a proposal with FERC outlining how their for-profit transmission company would operate under the umbrella of the MISO. The filing asked FERC to approve a proposed division of responsibilities between National Grid and the Midwest RTO. FERC responded to the filing with an April 25 order which approved some but denied other aspects of the filing. In addition, FERC said, "Alliance Companies are hereby directed to file a compliance filing within 30 days from the date of this order, detailing which RTO Petitioners plan to join and whether such participation will be collective or individual, as discussed in the body of this order."

While the Alliance as a group negotiated with both PJM and MISO, they were unable to come to a definitive agreement with either group. Facing a May 29 deadline to file their plans with FERC, each member decided to go its own way. Thus ends the Alliance.

ComEd, AEP, Illinois Power, and Dayton Power & Light have decided to join PJM. FirstEnergy, Ameren, and NIP-

SCO intend to join the Midwest ISO. Trans-Elect Inc., a private transmission company that recently bought the Michigan transmission unit of Consumers Energy is also handing over control of that system to the Midwest ISO. Dominion Resources (Virginia Power) is still considering its options. The companies each had their own reasons for their decisions, but essentially, each did what was in its best interest.

AEP intends to join PJM-West as either a transmission-owning member or a member of an independent transmission company. "We believe the interests of AEP's customers and shareholders are best served by participation in an RTO with an existing energy market and a proven track record of RTO-related operations and of assimilating new market participants," said J. Craig Baker, AEP senior vice president of Regulation and Public Policy. "Our participation in PJM-West will bring the benefits of RTO participation and the PJM energy market to our customers within a projected six to 12 months, sooner we believe than other options we considered."

AEP decided to enter into the MOU with PJM after evaluating FERC's April 25 order. AEP was concerned that FERC's allocation of functions described in its April 25 order, and the fact that this allocation may change over time, may not leave sufficient responsibilities with independent transmission companies for them to become viable businesses. FERC's ruling on the allocation of functions, along with the potential of protracted litigation between MISO and the Alliance companies over costs and revenue allocations, led AEP to make its decision on RTO participation.

Illinois Power also intends to join PJM, preferably through an independent transmission company headed by National Grid, along with other companies such as Commonwealth Edison and AEP. Illinois Power told FERC it would join PJM as a transmission owner, should it not join through an independent transmission company. Illinois Power said this arrangement provides greater flexibility and cost savings while maintaining reliability in moving large amounts of electricity across the nation's transmission grid. An important factor in the company's decision is

continued on page 2

IN THIS ISSUE

Are Summer Blackouts On The Horizon?
Page 3

FERC Tries To Standardize RTOs
Page 4

Should Siting Be Federalized?
Page 6

Can For-Profit And Non-Profit Co-Exist?
Page 7

Newsmaker Interview: Eric Freeman
Page 8

Private Use Laws; Friend Or Foe?
Page 9

Tech Brief: Flexible AC Transmission Systems
Page 10

Transmission In The News
Page 11

ALLIANCE RTO, CONTINUED FROM PAGE 1

that, like Illinois, many states within the PJM interconnect area already have electric choice. "The relationship with PJM will connect us and our customers with a robust electricity marketplace that is already up and running," said Illinois Power senior vice president and general counsel Kathy Patton. "The PJM region has already established the infrastructure, policies and business practices for operating a market. This will bring the advantages of a larger competitive market into our region much more quickly than other alternatives available to us. Once the market is fully integrated into this region, customers will have full access to resources in a vast area from Illinois to the East Coast with a single market transaction."

Commonwealth Edison is the third Alliance member to join PJM. "We believe that PJM is the best option for our company and our customers. It is clear that Exelon's primary wholesale energy trading partners and suppliers are in the east, and our strongest interconnections are to the east," said Moler. Moler added that ComEd customers will get a mature marketplace more quickly with real choices under PJM than with MISO. "The PJM Interconnection has a strong presence in key eastern markets, and market structures already in place for the region that are similar to what FERC is proposing in its current standard market design. The company also has a long track record of successfully operating energy markets and is the model for the industry."

Moler also noted that joining PJM has the benefit of putting the entire family of Exelon companies under a single regional transmission organization, with the ability to move power generated by plants in the east and west much more seamlessly. "ComEd negotiated with the MISO, but could not come to an agreement on rate structure and other matters," Moler said. "More importantly, our interconnections with AEP and our trading patterns to the east make PJM a far superior alternative for us. Once AEP chose PJM, it became clear that our overall business interests

would best be served by joining PJM."

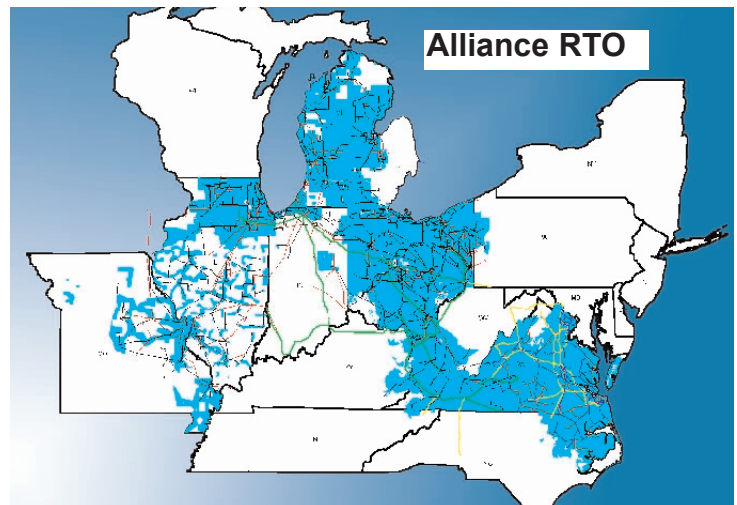
On the other hand, some major Alliance players aren't having the same problems with MISO. FirstEnergy Corp.'s subsidiary, American Transmission Systems, Incorporated (ATSI), has entered into a Memorandum of Understanding to join Midwest ISO. The MOU allows for ATSI to participate in the Midwest ISO as either a transmission owner or as part of an independent transmission company (ITC). "We believe that joining the Midwest ISO is the best course of action for many reasons, including Midwest ISO's established relationships with several ITCs," said Stan Szwed, vice president of transmission for FirstEnergy. "We made this decision based on our discussions with the Midwest ISO and the recent FERC order supporting our framework for developing an ITC within the Midwest ISO's regional transmission organization (RTO). The Memorandum of Understanding provides flexibility for the continued development of an ITC, including the Alliance Gridco, in which other Alliance companies can participate." FirstEnergy's transmission assets owned by its Pennsylvania Electric, Metropolitan Edison and Jersey Central Power & Light operating companies will continue to be operated by PJM.

While the Alliance RTO appears to be dead, the concept of for-profit ITCs isn't. As detailed above, many former Alliance members are still planning to form similar for-profit grid operators. An independent, well-run transmission sector is essential to the health of the electric industry, says Patton. She says the for-profit business model provides the right incentives to operate efficiently and move power

economically. "It will maximize throughput on the transmission system and attract the capital required to improve the necessary infrastructure," she said. "This is the same approach that has worked well for gas transmission."

In fact, ComEd, Illinois Power and AEP are proposing the formation of an independent transmission company that would be managed by National Grid while operating under the authority of the PJM Interconnection. "We believe an independent transmission company would provide the most efficient and most economical integration of these companies into PJM," Moler said. "The former Alliance companies have spent more than \$70 million to develop the infrastructure necessary to create an independent transmission organization. Continuing as an independent transmission company, while under the authority of PJM, allows us to use these existing systems to the maximum extent possible."

National Grid remains interested in managing and investing in those groups, said Nick Winsor, vice president of Transmission Strategy and Development at National Grid. "We feel that opportunity is still there," Winsor said. He said the company remains interested in making transmission purchases. "We would still be keen to play that role."



Transmission Insight, Volume 1, Issue 3

Editor: Steven J. Morris

For information, call 888-986-2250 (303-986-7449 in Canada or overseas) or e-mail custsvc@energyinfosource.com
Published monthly by Energy Info Source, 575 Union Blvd., Suite 107, Lakewood, CO 80228.

Data and information published in Transmission Insight is provided to Energy Info Source through a variety of industry sources and is published with the intention of being accurate. Energy Info Source can not, however, insure against or be held responsible for inaccuracies and assumes no liability for any loss whatsoever arising from the use of such data.

Single subscriptions are US\$249 for email delivery. Unlimited user site licenses by email are US\$599.

Copyright 2002 by Energy Info Source, Inc. All rights reserved. Reproduction by any means is illegal without prior permission.

ARE SUMMER BLACKOUTS ON THE HORIZON?

As the temperature heats up, the question of whether or not the U.S. faces any potential blackouts this summer has become an important one to answer.

The North American Electric Reliability Council (NERC) recently published a report designed to address the issue, expressing that the majority of the country is prepared for whatever heat that summer brings. All in all, the peak demand for electricity in North America is projected to increase 2.7 percent compared to the actual 2001 non-coincident summer peak. Significant amounts of new generating resources have been added in several regions since last summer and projected capacity margins have likewise increased, especially in ECAR, ERCOT, MAIN, and SPP. Even though a large portion of the country is expected to experience drought this summer, this should not lead to electricity shortages. There were only two sections of the country that the report singled out as potential problem areas -- southern Nevada and southwestern Connecticut.

In Nevada, the concern is not based so much on a lack of generating capacity or transmission, it revolves around the financial state of Nevada Power and the impact that will have on its suppliers. Industry analysts and other experts at NERC have predicted that Nevada Power will lose many of its suppliers, including independent power producers, due to its weakened credit worthiness.

Nevada Power has seen its bond ratings downgraded to junk status since the Public Utilities Commission disallowed almost half of the utility's \$922 million request to recover money it spent buying power last year. State regulators concluded that the company acted imprudently in some of its power purchases and that it should be prohibited from passing all of its costs on to customers.

Since then, a subsidiary of Enron and the Morgan Stanley Capital Group, have both stopped delivering electricity to Nevada Power. NERC experts predict that unless Nevada Power can pull itself out of its current rut, this trend will continue.

Don Soderberg, chairman of the Public Utilities Commission, personally feels that the forecast is a bit exaggerated. "We disagree with their (NERC's) analysis of the Nevada Power situation," he said, "We wonder if they are using a little bit of information that might not completely be up to

date." Soderberg acknowledged that power suppliers might prefer to deal with a financially stronger utility. However, he added that, "If they have megawatts for sale, they are not going to let their plants sit idle."

Soderberg believes that Enron's decision to stop power deliveries actually helped Nevada Power's cash situation, because its contracts with Enron were locked in at high prices. "We think their cash flow probably looks better now," Soderberg said. "They have not missed a payment."

Still, some analysts believe that Nevada Power would be better off if it filed for Chapter 11 bankruptcy, which would allow the company to reorganize its debts while continuing to operate. However, this is an option that Nevada Power hopes to avoid. Chairman and chief executive officer of Sierra Pacific Resources, the holding company of Nevada Power, Walt Higgins explains, "My opinion has not changed that bankruptcy should be avoided if possible. It's an option that's out there, and we know it is," he admitted, but continued to stress that, "We are working diligently to bring certainty to our power suppliers."

Currently, Nevada Power's is attempting to renegotiate contracts with its suppliers to deliver power for less than their current contracts specify, with the opportunity to collect the difference later. "If we get the power suppliers to go along with us, we should be able to make it through the summer, barring some unforeseen circumstances," Higgins said.

In addition, the company has sought regulatory permission to issue \$450 million in long-term secured bonds. However, Nevada Power won't know whether the financial markets will fund the bond offering until the PUC decides how much to raise the electricity rates at Sierra Pacific Resources subsidiary, Sierra Pacific Power.

Should Nevada Power be granted permission to release these bonds, the summer should pass without a glitch. However, if Nevada Power is denied this offering, a rapid depletion of funds could bring electricity service to an abrupt halt.

As opposed to financial problems, Connecticut's problems revolve around good, old-fashioned limitations associated with the transmission system. While ISO New England has projected that the 2002 summer capacity situation will be adequate, the continuing inadequacy of the

transmission system in this region could create critical localized reliability problems.

ISO New England expects power demand in southwest Connecticut to reach between 2800 to 3500 MW this summer. About 2000 of these MW can be generated locally, but the rest must be transported from other locales. If the transmission system were adequate, this would be fine. However, since southern Connecticut's transmission lines are ailing, it presents a problem. ISO-NE senior vice president and chief operating officer, Stephen G. Whitley, explains, "Electricity supplies have outpaced demand here in New England, but it's also a matter of location, location, location. Until more improvements are made to the region's transmission system, ISO New England will have to carefully manage power system operations during peak demand periods this summer and for the next few years," he said.

In recognition of the southwestern Connecticut transmission limitations, an Emergency Capability Supplement program will be implemented, a program that will negotiate the acquisition of 80 MW of additional temporary generation. Additionally, NEPOOL participants are contracting with customers in southwestern Connecticut and other parts of New England to receive payments to voluntarily reduce their demand. This temporary new generation and these demand reductions, in combination with conservation and use of emergency generation should enable the area to avoid rotating blackouts this summer.

Hopefully, situations such as this can be avoided this summer. ISO New England currently has more than 250 MW of new generation being developed in the southwest, all of which should be added to the grid by mid-summer. Still, Whitley continues, "The long-term solution is to upgrade the region's transmission system, upgrade generation capacity, and strengthen demand response solutions...Upgrades to the transmission system have been proposed, but these enhancements, if approved, will not become fully operational until 2004, at the earliest," he said. With a little luck, southwestern Connecticut will be able to hold on until then.

Happily and surprisingly, neither

continued on page 5

FERC TRIES TO STANDARDIZE RTOs

On November 7, 2001, FERC issued an order stating some of its goals and providing general guidance on how it intended to proceed on RTO filings and other related efforts. This order (Docket No. RM-01-12-000) laid out FERC's view that a standardized transmission tariff design and market rules were needed for RTO development to continue. According to FERC, "At present there is no single set of rules governing transmission of electric energy. The electrons moving across the grid do not distinguish between bundled retail and other services, and behave according to the laws of physics rather than the laws of a particular jurisdiction. With more non-integrated electricity suppliers and a deeper reliance on wholesale electric markets, there are substantial competitive consequences and higher costs to all retail customers if we do not apply consistent, non-discriminatory rules to all transmission customers. To protect all customers and assure the benefits of competition for all, consistent transmission rules must be applied."

This was FERC's first shot across the bow of the electric industry in what is likely to be one of the key moments in industry history -- development of a Standard Market Design for RTOs. According to FERC, "Market design flaws are visible in every regional electric market today under the existing tariff. These flaws are allowing operational problems such as the 'socialization' or 'uplift' of congestion management prices across all customers in a region, which obscures the potential for price signals to indicate where new generation, demand response or transmission is needed. In other regions, high fees are being collected for the value of generation capacity that do not clearly incent the construction of new capacity. A third type of flaw has been the sequential clearing of energy and ancillary service markets, which fails to deliver efficient prices for the service delivered. No region has been exempt from market design flaws of one type or another."

"What we've learned is that regulators can't simply open the markets, adopt any old market design, and declare let 'er rip. We can't be satisfied with chaotic markets, poorly-designed markets, and markets that don't provide customer benefits," said FERC Commissioner William Massey.

FERC believes that by standardizing tariff design and market rules, it can pro-

vide more choices and improved services to all wholesale market participants; reduce delivered wholesale electricity prices through lower transactions costs and wider trade opportunities; improve reliability through better grid operations and expedited infrastructure improvements; and increase certainty about market rules and cost recovery for greater investor confidence to facilitate much-needed investments in this crucial economic sector. However, FERC also recognizes that a key challenge for it will be to balance the need for standardization with the need to permit regional differences and market innovation.

The first step in FERC developing its "Standard Market Design" was a concept paper published by FERC staff on December 17, 2001. The paper presented a view of what the electric industry should look like by 2010, as well as the industry

"What we've learned is that regulators can't simply open the markets, adopt any old market design, and declare let 'er rip. We can't be satisfied with chaotic markets, poorly-designed markets, and markets that don't provide customer benefits."

FERC Commissioner
William Massey

functions needed to make this vision a reality. This paper served as a basis for discussion as FERC held several conferences to gather data for its Standard Market Design order. The first conference, held in late-January, had the goal of gaining a mutual understanding of similarities and differences between various market designs and allowing participants to provide further detail on market operations. The second conference, held in early-February, was to discuss the technical issues relating to a standard market design for wholesale electric power markets. The third conference, held in mid-February, was to discuss the allocation of RTO characteristics and functions between separate organizations within an RTO region. A fourth conference, not yet held, will discuss data and software needs in connection with a standard market design.

As a result of the three conferences,

FERC issued a working paper on "Standardized Transmission Service and Wholesale Electric Market Design" on March 15. In the working paper, FERC provides some broad guidelines for what it views as important characteristics of the standard market design. These characteristics include using LMP as the system for congestion management, the availability of a nondiscriminatory, standard "Network Access Service" for all customers, RTO operation of bid-based day ahead and spot markets, the ability for holders to sell transmission rights, and preventive mitigation measures in the form of bidding rules. NYISO president and CEO William Museler said the working paper "provides an excellent framework and vision for creating the national electric system of the future."

Following on the heels of its working paper, on April 10, FERC distributed an options paper for resolving rate and transition issues for its standard market design effort. Specifically, it addresses embedded cost recovery, transmission rights allocation, and transitioning existing contracts and services to FERC's proposed Network Access Service. One particularly troubling problem is the allocation of existing rights. The paper proposes four solutions: 1) assign rights based on historical usage, 2) auction rights and assign revenues to existing rights holders, 3) allocate a portion of the rights and auction off the rest, and 4) allow for regional variation if and only if an RTO is in place when FERC institutes standard market design.

Initially, not everyone agreed that FERC even had the authority to undertake such an effort. In a filing with FERC, the North Carolina Utilities Commission stated, "Current federal law does not support the Commission's goal of 'nationalizing' electricity, and clearly there is no current consensus in Congress that favors granting the Commission authority broad enough for it to force States to unbundle retail service and obliterate integrated resource planning." However, on March 4, the U.S. Supreme Court affirmed an appeals court ruling that FERC had the authority to implement its 1996 rule (Order 888) requiring investor-owned utilities to open their power lines on an equal basis to competitors. The ruling was a blow to state utility regulators who had argued that FERC usurped their authority. The case was

continued on page 5

FERC STANDARDIZATION, CONTINUED FROM PAGE 4

brought by state regulatory agencies from New York, Florida, Idaho, New Jersey, North Carolina, Virginia, Washington, Vermont, Wyoming, and the National Association of Regulatory Utility Commissioners.

North Carolina isn't the only state fighting FERC's effort. In a filing with FERC, New Mexico Attorney General Patricia Madrid states, "The New Mexico Attorney General opposes FERC's efforts to seize jurisdictional control of all utility transmission assets through the formation of RTOs. Under the Federal Power Act, FERC was given jurisdiction only over wholesale transactions and transmission matters. By seeking the formation of RTO 'middlemen,' FERC is seeking to transform utility retail transactions into wholesale transactions over which it would then have jurisdiction. The New Mexico Attorney General believes that preservation of utility control of transmission under state regulation is fundamental to protection of retail electric service." AG Madrid goes on to say, "The Attorney General can not agree to allow the transmission owning electric utilities within the state of New Mexico to join WestConnect if FERC does not agree that the New Mexico Public Regulation Commission will retain the

right to set retail transmission rates for all customers.

However, all is not doom and gloom for FERC as utilities seem to be getting behind FERC on standard market design. David K. Owens, executive vice president for business operations of the Edison Electric Institute (EEI), said, "We strongly endorse the Commission's ambitious effort to forge a national standard market design, and we believe the Working Paper lays out an excellent framework. Many of the elements in the paper are on target, while others will require more consultation from the states and other stakeholders." While recognizing the need for absolute coordination between market operations, system dispatch and system control, the Institute reaffirmed its strong support for diversity regarding RTO and transmission business models. "It is vital that we adopt a pluralistic approach to these business models," said Owens, voicing EEI's support for preserving the independent transmission company model. Owens concluded. "EEI believes that significant progress toward implementing a standard market design will bring regulatory stability -- which will foster the needed investment in the nation's electric system and ultimately deliver greater benefits to consumers."

Cooperative utilities through their representative, the National Rural Electric Cooperative Association (NRECA), also support FERC's effort, but have some concerns. In a filing with FERC, NRECA requested that the commission address in greater detail the issues of transmission access and grandfathered power contracts. "Electric cooperatives want the commission's assurance that their ability to serve their members will not be compromised by any new regulatory regime," said Rich Meyer, NRECA Senior Regulatory Attorney. In its filing, NRECA supported the commission's proposal to encourage the construction of new transmission and generation facilities, while expressing its hope that any final rule not subject co-ops to the ill effects of market power or hinder service to co-op members. "As locally owned, democratically controlled businesses, electric co-ops appreciate the commissioner's open minded approach," said Meyer. "We look forward to working with them to identify where improvements can be made and efficiency gained."

After gathering all the comments to its white paper and option paper, FERC currently plans on issuing a Notice of Proposed Rulemaking on the subject this summer.

SUMMER BLACKOUTS, CONTINUED FROM PAGE 3

California nor New York were noted as areas of concern. The balance between capacity and demand in California has improved since last summer due to decreases in the demand for electricity and the addition of about 5000 MW of new generating resources in the area. The addition of about 450 MW of new resources in New York City and Long Island as well as the unfortunate elimination of a need for power at the World Trade Center has enabled these areas to reliably serve their customers as well.

California especially is in very good shape, noting that it has reduced its demand by about 3300 MW and increased available resources by about 5000 MW in the last year. Unlike last year, hydro resources are at normal levels, which also serves to improve the energy supply at non-peak hours.

On the other hand, while not a problem area for this summer, the New York/ Long

Island area cannot simply sit back and relax. The assessment notes that the area will need an additional 7100 MW by 2005, 2000-3000 of which must be located in New York City. This necessity for capacity results in transmission concerns that will need to be addressed within the next few years as well.

The current situation has been the result of growing disparity between electricity demand and supply. Between 1995 and 2001 in New York, statewide demand for electricity rose by 3280 MW, while generating capacity increased by only 1720 MW. Should this trend continue, New York and Long Island will find themselves a significant area of concern within the next few years.

At the request of New York State, the NYISO is preparing an assessment of the State's transmission system, which will identify potential high-value transmission infrastructure projects that could increase

reliability and market efficiency. The assessment will be completed by the end of 2002. In the meantime, NERC advised New York to encourage distributed generation in the area.

NERC also stressed the importance in considering fuel diversity as it relates to the economics and adequacy of energy supply in New York. NERC believes that the expansion of natural gas transmission infrastructure as part of New York's energy policy is essential to the vitality of the region. The NYISO has taken steps to implement this recommendation by jointly undertaking a study with NYSERDA to examine the impact of increased demand for natural gas on the state's electric system and natural gas infrastructure.

Thankfully, New York has time and can still remain relatively optimistic. Even happier, it seems as though the entire country is relatively prepared for the scorchers that lie ahead.

SHOULD SITING BE FEDERALIZED?

In early May, Secretary of Energy Spencer Abraham unveiled the National Transmission Grid Study (NTGS), a project developed in response to the President's National Energy Policy directive to Secretary Abraham to study the Nation's transmission system, identify transmission bottlenecks and identify measures to eliminate those bottlenecks. The study recommends ways to facilitate investment in the Nation's transmission infrastructure to improve reliability and reduce electricity costs to consumers. One of the recommendations is to accelerate the siting and permitting of transmission projects by providing FERC with the ability to grant the right of eminent domain to projects.

One of the most obvious industry trends of the last few years is that the need for electricity transmission system improvements is growing. However, at the same time, it has become increasingly difficult to obtain approvals from state and federal agencies for the siting and construction of major transmission additions or upgrades. In addition, although wholesale power markets are becoming more regional, the existing system for siting and permitting of transmission facilities remains mainly state based. Lengthy siting processes add uncertainty, expense, and indefinite delays to the construction of new transmission lines.

In the NTGS, the Department of Energy (DOE) indicates that it wants states to remain involved in the process, but with more of a regional and national perspective. "State and federal regulators must work with states and regions to ensure that transmission siting and permitting processes work -- and work together. States should retain their present authority and play a more active role in managing review processes for energy infrastructure siting and permitting. As part of their reviews, states should ensure that regional considerations are taken into account in assessing the costs and benefits of new transmission. They should also coordinate their reviews with other regional and state planning, siting, and permitting processes," says the report.

However, DOE also recognizes that when disagreements occur that threaten the ability to approve the project, the federal government must step in. "Federal regulators should actively support and defer to these state and regional siting and

permitting processes. However, since new regional transmission facilities will typically span or impact multi-state areas that seldom align with the political boundaries of states, FERC must have appropriate backstop authority to ensure that the public interest is served and that national interest transmission bottlenecks designated by DOE are addressed. When state and regional processes determine that construction of transmission facilities is needed to address national interest transmission bottlenecks, yet are unable to site or permit them in a timely fashion, FERC must be able to grant designated entities the right of eminent domain to acquire property for rights-of-way."

As expected, this suggestion is not being taken very well by the states. Therefore, in order to stem criticism, DOE is suggesting a limited role for FERC. "DOE believes that Congress should grant limited federal siting authority to FERC to be conveyed only when a transmission facility that would significantly advance national interests is in jeopardy of not being built and only after regional bodies have determined that this facility is preferred among all possible alternatives," says the report. Yet even this limited role is likely to have its critics.

In testimony before Congress, Alan Schriber representing the National Association of Regulatory Utility Commissioners (NARUC), said, "NARUC strongly disagrees with the presumption permeating here in Washington that the root cause of all transmission congestion problems in this country is State eminent domain and siting authority, and therefore the Federal government must step in. A major impediment to siting energy infrastructure in general and electric transmission in particular is the great difficulty in getting public acceptance for needed facilities. This tells us that no matter where siting responsibility falls, with State government or the Federal government, siting energy infrastructure will not be easy and there will be no quick fix to this situation." He continued, "Giving the Federal Energy Regulatory Commission (FERC) eminent domain and siting authority is not a panacea. Beyond the practical matter of the time FERC would need to be prepared to assume this new role and the additional funds that Congress would need to appropriate to accomplish this, how many examples actually exist where a State action (or

inaction) is solely responsible for unreasonably preventing a needed transmission project?"

The state regulators have been joined in their opposition to FERC having eminent domain authority by state Governors. In a letter to the Senate Energy and Natural Resources Committee, Western governors opposed as "unwarranted and inappropriate" proposals to preempt state authority over transmission line siting. They also said decisions on and enforcement of reliability standards should be made by the affected region, not FERC. "Western states, collectively and individually, have been very aggressive in addressing a wide range of energy issues, from extensive conservation measures to the siting and permitting of new generation," said Gov. Jane Dee Hull of Arizona, chairman of the Western Governors' Association. "We have agreed to move forward on a plan for streamlining the permitting of interstate transmission by next June. We have clearly demonstrated that decisions on these issues are best made at the smallest, most appropriate geographic area."

It's no surprise that the states would be against FERC invading their turf. But how do other industry stakeholders view this debate. John Anderson, executive director of the Electricity Consumers Resource Council (ELCON) said, "Congress needs to ensure that transmission is subject to federal regulation, not a hodge-podge of sometimes conflicting state and regional rules. Congress needs to affirm that the interstate transmission system is operated in an open and non-discriminatory basis, as FERC intended in issuing Order 2000, so as not to deter wholesale competition. And Congress needs to make the transmission siting process less cumbersome by establishing a federal right of eminent domain."

So customers, at least large ones, are in favor of federal intervention. How about the utilities themselves? In comments submitted to DOE regarding the NTGS, the Edison Electric Institute (EEI) said, "EEI supports granting FERC a backstop role to help site new transmission lines when states or federal agencies are unable or unwilling to agree on new transmission line applications."

Further explaining EEI's position, Stanley Szwed, vice president of Transmission for FirstEnergy, said in

continued on page 7

CAN FOR-PROFIT AND NON-PROFIT CO-EXIST?

As the energy industry restructures and RTOs form, interest in developing Independent Transmission Companies (ITCs) has surfaced. These ITCs would operate as stand-alone for-profit transmission businesses, separate from but interrelated to RTOs. To what degree this idea is an advantageous one is still up for discussion.

The concept behind an ITC is to provide a means for owning and managing transmission lines independent from the utility. By surrendering transmission lines to an ITC, the transmission system can be operated by one entity from one location, making it easier to delegate the lines, operate the system, perform maintenance, and build new lines, all without a concern about independence. ITCs for-profit nature with a focus on the transmission business is ideally suited to bring about: 1) improved asset management including increased investment, 2) improved access to capital markets given a more focused business model than that of vertically-integrated utilities, 3) development of innovative services, and 4) additional independence from market participants. However, while most agree that a transmission-only company is a good idea, the proper way to structure this company has complicated the concept.

There are basically two approaches to forming an ITC. The first is where the ITC has full responsibility for all transmission activities -- essentially a for-profit RTO. For-profit RTOs revolve around property rights that would expect control of assets to go hand in hand with ownership. Despite the fact that it would be a monopoly with an incentive to disadvantage competitors, such as generation, believers in this model expect that the implementation of performance-based incentive regulation would serve to align the interests of users and owners regardless of the lack of independence. With substantial transmission assets at risk, regulators would have the tools and shareholders the motivation to improve performance and maximize efficient utilization of the grid.

The other principle model is that of the hybrid ITC-RTO. This concept serves to downplay the non-competitive aspect of a transmission entity and separates the ITC from performing market functions. In this model, the ITC must initially meet and adhere to Order 2000. Here, the model is a direct part of the RTO, one that is separate

only to avoid effecting competitive decisions impacting the grid. However, the two entities would operate under the same rules and in essentially the same way. The ITC would receive tariff-based rates to cover revenue requirements for the grid and would also act as the regulated transmission investor for any economically justified grid enhancements recommended by the RTO grid planning process. The ITC would recover its revenue requirements and pursue regulated rates of return for these regulated (non-market-based) investments, just as regulated utilities do now.

The Federal Energy Regulatory Commission (FERC) clearly prefers the hybrid ITC-RTO model. On April 25, it issued an order granting TRANSLink's proposal to form an ITC under the auspices on the Midwest ISO (MISO). FERC intends that this order form the basis for future ITCs. "Today's order establishes an efficient and effective framework for hybrid RTO formation. This framework successfully captures the benefits associated with large, regional RTOs and simultaneously captures the significant benefits associated with the ITC business model. Under the hybrid RTO and ITC models approved today, ITCs will be given the opportunity to profitably own and manage their independent transmission businesses through a combination of efficiency enhancements; operational, service and contractual innovations; and, in general, exploiting their significant experience and insights into the efficient utilization and expansion of the nation's transmission Infrastructure," says FERC.

Specifically, FERC will not allow an ITC to maintain its own tariff saying it is important for the RTO to operate under a single tariff with only necessary variations from zone to zone. However, it will allow an ITC to maintain a separate schedule within the RTO's tariff to facilitate different rates and a different rate design. FERC will permit ITCs to unilaterally file rate structure and incentive rate proposals as part of a revenue requirement request, after consultation with the RTO. Under this approach, the ITC would have unfettered rights to file its revenue requirement and/or incentive rates within its footprint, i.e., only for transactions that source and sink within its footprint. The principal responsibility for managing parallel path flow should lie with the RTO, since the

larger the area served, the more parallel path flow is internalized. ITCs can provide System Control, Voltage Control, and Regulation Services, but the RTO will be the PLR of ancillary services and imbalance energy to transmission customers taking service under the ITC schedule.

But FERC is not unanimous in its views on hybrid ITC-RTOs. Commissioner Linda Breathitt said, "I am still concerned that our calls on each of the functions may not allow ITCs to fully prosper and fulfill all of the bright promise that we see in these entities. I am frankly worried that we are using one hand to pat ITCs on the back for bringing us a structure that we hope will result in new infrastructure and improved use of their existing interstate transmission lines, and using the other hand to take away many of the functions that they asked to retain to be a viable business under that structure."

SITING,

CONTINUED FROM PAGE 6

testimony to Congress, "It made sense in 1935 when the Federal Power Act was adopted to leave transmission siting authority with the states, since transmission lines were generally local in nature. It also made sense for Congress to grant FERC's predecessor, the Federal Power Commission, authority to make siting decisions for natural gas pipelines, since they tend to be interstate in nature. Now, however, our transmission system is being asked to meet obligations similar to natural gas pipelines: move large amounts of energy across long distances and across state lines. We understand that the issue of federal eminent domain authority raises concern. Of course, to carry out necessary siting, there must be a certificate of public convenience and necessity issued. Only then may the holder of the certificate exercise the authority. The FERC currently has authority to issue certificates for natural gas pipelines and for electric transmission for hydroelectric projects. In addition, the federal electric utilities that own transmission have eminent domain authority."

While it's evident that consensus on this issue will be hard to reach, clearly the ball is in the state's court to come up with an alternative solution to FERC that can achieve timely permitting and siting of multi-state transmission projects.

NEWSMAKER INTERVIEW: ERIC FREEMAN

In 2002, Spain's GRUPO AIA launched its U.S. operations with the formation of EleQuant, headquartered in San Francisco. EleQuant's focus is on providing technology and software products to utilities, independent system operators, regional transmission operators and other organizations involved with management of electricity grids in the U.S. and Canada.

Founded in 1988 and based in Barcelona, Spain, GRUPO AIA is a technology and software development company that specializes in solving complex problems for the energy, banking and telecommunications industries. The company is known throughout Europe for developing innovative solutions in areas such as intelligent observation and management of electrical grids, electricity demand forecasting, and river basin hydro-generation optimization.

EleQuant provides technology for real-time intelligent observation and management of electricity flow in the United States. Designed to improve system reliability, the Advanced Grid Observation Reliable Algorithms (AGORA) technology allows power system operators to effectively simulate the activity on a power grid under any condition, allowing for more accurate operations and planning. PG&E became EleQuant's first U.S. customer when it purchased AGORA in 2001 to help manage its 18,000-mile system. Utility companies in Spain, including Red Electrica de Espana S.A. and Endesa, also use the software.

To learn more about the technology and about EleQuant itself, *Transmission Insight* spoke to V.P. and General Manager of EleQuant, Eric Freeman.

TI: Why don't you start by telling me what AGORA is?

EF: The product is a comprehensive suite of applications for transmission operators and is primarily used for three things -- grid observation, restoration, and for planning. It provides grid operators with real-time monitoring and observation tools, voltage collapse assessment, restoration analysis, system-wide or localized disturbance restoration, powerful, fast and reliable load flow, a load forecast calculator, and it minimizes losses on the grid.

TI: What prompted its development?

EF: Everything that's been used in the electrical power industry since the 60's has

been based on a certain algorithm, called the Newton-Raphson method. It works pretty well, so long as today is just like yesterday. But with growth and change it's running into problems. The current algorithm has difficulty calculating when you get close to voltage collapse, which is exactly when you need it most. So, the idea behind AGORA was to have an algorithm that gave an accurate measurement all the time, that way you can walk right up to edge of the cliff without being concerned about falling over. Unfortunately, the software that's employed worldwide today doesn't always show the edge of the cliff. Ours does and that's where the breakthrough is at.

TI: Even though AGORA is only now coming to the United States, it has been in use in Europe for some time, correct?

EF: The technology has been in use in Spain in an earlier form since 1991, so we've been working with electric utilities in Spain since 1991. Here in the US, we are focusing on delivering this technology to utilities that are most interested or most concerned about some of the problems facing companies in the electric power market today, especially transmission companies.

TI: I understand PG&E is your first American customer. How did they become involved with AGORA?

EF: It's a really beautiful story because we are a small European development company and PG&E is this huge American utility. We were referred to PG&E from people from the CAISO who thought, with the California Energy Crisis, that they might be interested in a very reliable and accurate solution so for the first time ever in 150 years they sent engineers to Barcelona to visit with AIA and to see European customers using and relying on our solutions. That's what led them to try and ultimately buy our software. It's a big company and to get the approvals necessary to send three engineers to Barcelona, it involved a lot of paperwork, but ultimately it worked out.

TI: How is the product installed?

EF: What we do is we take the same data that come off the existing EMS system and bring it into our solution so it doesn't disrupt anything that is already there, it's just like plugging in another appliance to an existing outlet. So we take the other

data stream and we crunch it differently and by virtue of it being a very special algorithm it ends up being much more reliable and accurate all of the time.

TI: How much does the technology cost?

EF: It's very competitively priced, between three and five million dollars, depending on the size and complexity of the system. But the value is fantastic. One of the major benefits with a very accurate and very reliable load flow is the restoration capability. We have an optimal restoration package which provides an adaptive and dynamic restoration solution to companies to restore power at certain geographies. This is something that has been shown to be very effective in Northern California, to be able to reduce the restoration time significantly, so it represents this very significant cost savings for the company and the clients. AGORA can also reduce the required engineering staff hours by 90% because it makes so many tasks that were manual automatic.

TI: Is there much maintenance involved?

EF: So as long as it receives the data flow from the EMS data system, there is very little additional maintenance and the actual installation is very simple too. From our work in Europe and the US we've had experience with most major EMS data systems so that part is already done. Installation time is sure to be within two to four months and that's including time for testing.

TI: What challenges do you face in implementing the product?

EF: The biggest thing is just that it's a pretty traditional industry and it's undergoing more challenges today than ever before, so there is a lot of interest in finding a solution that will provide the right answer all the time. But, then there is a lot of resistance towards change because the industry has grown over the last 35 years with a certain methodology that is inherent everywhere so our biggest challenge is introducing these new solutions that provide greater reliability than before but that are rooted on something very basic and very core. It's just hard to introduce something so new and so special to people who have been so used to doing things the traditional way.

PRIVATE USE LAWS; FRIEND OR FOE?

As the electricity industry unbundles, it is becoming increasingly evident that many of the rules that were enacted in previous years are no longer applicable, nor do they benefit, a competitive marketplace. One law that is thought by many to fall into this category is that of private use.

"Private use" refers to federal tax laws which restrict the ability of publicly owned utilities to sell and transport electricity to private parties, such as investor-owned utilities (IOUs) and power marketers. The current private use restrictions were enacted in the 1986 Tax Reform Act -- long before anyone seriously considered restructuring the electric utility industry. Therefore, it's no surprise that private use laws hinder the development of a competitive electric industry.

Since public utilities are non-profit, they have some advantages over for-profit investor-owned utilities (IOUs). Private use is one of these advantages. Under current federal tax law, all units of state and local government, including public power systems, can issue tax-exempt bonds to finance certain capital investments. The bonds are subject to "private use rules" in the federal tax code designed to limit the amount of benefit private parties may receive from these investments. The IRS' private use rules severely limit public power's ability to sell excess low-cost electricity outside of their traditional service territories or to participate in RTOs. With the coming of retail competition, public power systems will be expected to open their territories and participate in RTOs.

Currently, public utilities are exempt from federal income tax as long as 85 percent or more of their income comes from its members. Private use restrictions; however, hamper the ability of public power systems to participate in RTOs, make transmission upgrades and provide transmission access, or sell surplus power under long-term contracts. Such transactions can place outstanding tax-exempt bonds at risk if they allow private participation that is higher than the restrictive limits set by the private use rules. The penalties for permitting too much or inappropriate "private use" are severe: bondholders will retroactively lose the tax-exempt status of their investments and the utility will be forced to redeem some or all of their bonds.

Public utilities say private use rules

need to be changed so that they can join RTOs and open their markets without losing their tax benefits. However, not everyone agrees with them. Current tax laws allow public utilities to issue tax-exempt debt, which means they pay 2 to 4 percentage points less interest on their debt, for a cost of capital roughly 20 to 25 percent lower than investor-owned utilities pay. In the old, noncompetitive world that differential didn't matter much. But in a restructured electric industry, the difference in debt costs is significant, giving public utilities a marked advantage in competing with investor-owned utilities. Public utilities want to maintain that advantage as they begin to compete. Investor-owned utilities want public utilities to convert all debt into taxable debt if they decide to compete.

The public utilities maintain that their goals are different from the goals of IOU's and that the tax laws simply reflect those differences. Public utilities feel that the people have the right the purchase power from a government-owned utility and that as long as those utilities are owned by the government, they should remain tax-exempt. Furthermore, the public utilities feel that they should be able to seek out customers wherever they want, as the choice is the same no matter the locale. However, in the name of compromise, the public utilities have generally agreed to void their tax-exempt status on new generation facilities, provided that all existing debt remains tax-exempt and that the public utilities can use their tax-exempt status for transmission, distribution, upgrades, and expansions of existing facilities. Additionally, the public utilities feel that all transmission facilities (public and private) should be turned over to a non-profit Transco to be managed.

IOUs can't help but like the idea that in order to maintain their tax-exempt status in a deregulated world, public utilities might be forced to open their territories to competitors without being able to compete for the IOUs' customers. IOUs contend that there is no legitimate governmental purpose in encouraging or even allowing munis to extend their market share, so no special subsidies or benefits should be extended to such efforts. This is advantageous to IOUs because they gain the ability to emerge within a public utility's territory without risking the territory that they already occupy.

Is there a solution to this issue? Like with any good debate, several compromises have been offered. While the IOUs are not as yet completely unified in their suggestion, a number of compromises seem to be generally widespread. The IOUs (in general) believe that the public utilities should be offered a choice; to remain tax-exempt provided they sell only within their traditional service area, just like things have always been, or else enter into the competitive market as a commercial entity and be treated as such, which means the refinancing of current debt and no more exemptions from taxes on future debt. The Edison Electric Institute (EEI), representing IOUs, says, "Legislation should be enacted to ensure that public utilities can retain their tax-exempt status and their identity as an organization with different interests for those that wish to expand their service options while retaining their distinct identities."

Meanwhile, public utilities want to keep their status and still participate in competitive markets. The American Public Power Association (APPA), representing public utilities, says, "Current restrictions on the 'private use' of tax exempt bonds hamper public power's ability to provide access to their transmission lines, join regional transmission organizations, and sell excess power under long-term contracts. Outdated tax laws must be replaced by new provisions that reflect the new marketplace."

The IRS has attempted to address the issue by way of temporary and proposed rules. However, these attempts have not been highly regarded. It is governmental legislation that is needed to provide certainty for public power systems to make decisions about how new facilities may be financed and how to operate existing systems in today's electric utility market.

Several congressional bills have tried to resolve this issue in the last year, but so far none of them have passed. The Energy Tax Incentives Act of 2002 (S.1979) calls for the U.S. Treasury to report to Congress by December 31, 2002 on the temporary "private use" regulations issued in January 2001, and make recommendations for Congressional changes. The bill has not yet been voted on by the Senate. For now, it seems that the only thing that everyone can agree upon is that change is needed. Exactly how the debate will conclude remains to be seen.

TECH BRIEF: FLEXIBLE AC TRANSMISSION SYSTEMS

Beginning in the late-1800's, when the electric industry first took off, there were problems managing the flow of electric energy through the system. In simplest terms, as electricity travels through the system, many transmission lines become overloaded while others are never fully utilized. Flexible AC Transmission Systems (FACTS) solve this problem.

Using high voltage, high current electronic devices, namely superconductors, combined with communication links and automatic controllers, FACTS enable electrical power transmission circuits to operate at a level that is closer to the thermal limit of the transmission wire. This technology reduces the strain on overused transmission wires and provides increased capacity on underused lines.

The technology consists of high power semiconductors configured in a three-phase inverter that together generate power. The voltage is then injected into the transmission system to control the flow of power on a given transmission line. Because the power can be added to the line very quickly, the transmission system becomes more stable and reliable in a way that offers the power supplier a lot of flexibility. The supplier can load a line up near its thermal limit when necessary, and reduce the amount of power on the line when such generation is not needed. The supplier can also relocate power within the system to meet increased demand in different sectors of the service area. FACTS also allows for alternative energy sources to be connected to the existing transmission network without installing additional transmission lines to accommodate the new sources.

Senior Communications Manager for Siemens, Rita Simonetta, comments, "Inverter-based FACTS can allow up to 50 percent more power to flow over specific lines," she says. FACTS systems also require a very minimal amount of maintenance.

Siemens Power Transmission & Distribution, Inc., located in Raleigh, N.C., is a principle developer of FACTS. The company offers a full line of the systems, including a Static Synchronous Compensator, a Unified Power Flow Controller, a Back-to-Back STATCOM and the latest Interline Power Flow Controller.

The Static Synchronous Compensator (STATCOM), developed by Siemens, the Electric Power Research Institute, and the

Tennessee Valley Authority is a solid state voltage generator that consists of a multi-pulse, voltage-sourced converter connected to the transmission line. It can quickly and accurately counteract both rising and falling demand and can transition from a state of full capacity to a lesser capacity in $\frac{1}{4}$ of a cycle. In addition, the system uses a modular, electronic structure that minimizes installation and maintenance costs and allows for expansion and relocation as grid requirements change.

The Static Synchronous Series Compensator (SSSC) is a solid-state voltage generator connected in series with the transmission line. This device is extremely valuable as a precise power, flow controller because it can vary the effective transmission line reactance independent of the line current flow. In short, the SSSC actually controls power flow to prevent overload.

A Unified Power Flow Controller (UPFC) offers grid operators the ability to overcome many transmission restraints. These systems can independently control both real and reactive power flow to maximize line utilization and system capability. UPFC's can also be used to minimize the current flow, thereby reducing system losses. UPFC's allow the controller to simultaneously and selectively control all three parameters effecting power flow, transmission voltage, impedance and phase angle, which is a concept that was next impossible before these systems.

It is also possible to use two SATCOM's back to back. This set-up allows the controller to utilize the maximum functionality and versatility of the power delivery. Using two systems enables the controller to transfer power between the two networks, resulting in long-term economic and system operation benefits beyond those of any other traditional means.

The Interline Power Flow Controller (IPFC), is the latest of Siemens FACTS technology. This system provides the maximum flexibility in the control of power flow. The IPFC can link multiple transmission lines and route power from overloaded to under-utilized lines. New York Power Authority is in the process of implementing such a system. Use of an IPFC system can raise the limit of power transfer, relieve major transmission bottlenecks, improve voltage control, defer construction of new transmission lines by maximizing use of existing assets, reduce system

losses, increase system reliability and flexibility, and increase the effectiveness of bulk power transfer.

Simonetta continues, "Right now, Siemens is experiencing some uncertainty in the market because of the lack of legislation and passing of an energy bill. Deregulation has caused many utilities to delay their transmission investments because they are unsure of who will own that asset in the future and how they will recover their investment if they cannot roll the cost into their rate base. So many utilities are playing a waiting game to see what the FERC will decide regarding the formation Regional Transmission Organizations and merchant transmission plans. However, there aren't very many disadvantages to the technology itself," she says.

Siemens has installed a number of the systems, the most recent of which being at the New York Power Authority. Simonetta comments, "There has been much written about the NYPA project because they are very pleased with the performance of the system." The project was initiated in 1999 and consists of a Convertible Static Compensator (CSC), currently operating at the Frederick R. Clark Energy Center. A \$48 million project, the installation resulted in a 60 percent increase in the amount of power that can be released over the Center's transmission lines. Former Power Authority Chairman and current trustee, Joseph Seymour, commented, "By making better use of existing transmission lines, the Power Authority is helping to meet New York's commitment to the environment," he said.

American Electric Power has also implemented a Siemens system. Located at the Inez Substation in Kentucky, the system was the world's first UPFC. Installed in 1998, the system has a capacity of 138 kV and is the world's largest inverter, which is actually two 160 MVAr inverters working together. They can be operated independently or interchangeably and have proven effective at regulating voltage and are also capable of controlling power flow. V.P. for Energy Delivery Support at AEP, Bruce Renz, says, "Inez is a major coal mining area, and electricity sales have steadily increased over the years. The UPFC helps us maximize use of our lines... It is extremely satisfying to see concepts we imagined a decade ago become reality," he said.

TRANSMISSION IN THE NEWS

NE Power Prices To Rise In Joint Market

Wholesale power prices in New England could rise about \$62 million by 2005, if the region moves ahead with plans to combine its electricity market and transmission system with New York state's, according to a study conducted by grid managers in both areas. This increase, which represents about 2% of projected power traded through New England's market, would result from cheap, plentiful power flowing south, where supplies are older and more expensive. New York, as a result, could see wholesale electric prices fall about \$282 million in three years, when market operators ISO New England and the New York Independent System Operator envision having a single market in place. That would represent about 6% of wholesale power trades processed by the state's market operator, according to the study. The benefits of a combined market are expected to reach more of an equilibrium over the next decade, as New York is seen building more efficient generation while power plant growth in New England tapers off, according to the study. By 2010, New England is likely to see a price savings from a combined market of about \$3 million, or 0.1% of its total wholesale power cost. New York's benefits are forecast to slide to about \$147 million, or about 3% of power traded through the ISO, according to the study. ISO New England and the New York ISO conducted the cost-benefit analysis as part of their exploration of the possibility of creating a single power market in the Northeast U.S. The logistics associated with combining the New England and New York markets would cost about \$35 to \$60 million, the grid managers said.

FERC Okays Revised NY Market Mitigation

FERC approved revised measures to prevent price spikes in the New York power market. The commission unanimously approved the New York Independent System Operator's latest "market mitigation" program to prevent sudden price surges. The New York ISO has refined its automated mitigation procedures for the day-ahead power market and plans to increase consultation and software coordination with neighboring

power grid operators. It will retain its current price and bid caps, while providing regulatory in the day-ahead market exemption for suppliers of 50 megawatts or less. FERC Chairman Pat Wood III said New York's program could be instructive for two major decisions the commission plans later this summer -- a rule on standard market design for the country's regional power grid operators and a decision on market mitigation measures in California and other western states. Wood said he was critical of the New York ISO's market mitigation measures until looking at them more closely in recent weeks. Although the New York program is based on a complex algorithms, it has "the virtue of upfront certainty," he said.

MISO, SPP Merger Moves Forward

Action by the Federal Energy Regulatory Commission (FERC) will facilitate the completion of the merger between the Midwest Independent Transmission System Operator, Inc. (MISO) and Southwest Power Pool (SPP), the organizations announced. At its meeting, the Commission acted on a request by the Midwest ISO and SPP to consolidate their tariffs. The Commission approved the consolidation of the two tariffs when the merger closes and directed the combined company to file a single tariff by November 1. The Commission also approved certain revisions to the Midwest ISO membership agreement involving the makeup and size of the new company's board of directors. The integration of the two organizations is already in process. Officers and the management of the functional areas have been named. Additional staffing is to be completed by June 4. The order marks the first in a series of federal and state level regulatory requirements necessary for the MISO and SPP's merger to move forward. The merger is on schedule to close at the end of the third quarter this year.

CAISO Accused Of Manipulating Market

State Sen. Joe Dunn, chairman of a legislative panel probing California's power debacle, said the Independent System Operator (ISO) had engaged in "repeated and questionable" behavior as electricity

prices spun out of control leading to blackouts around the state. Officials at the ISO -- which oversees the state's electric system -- said they would look into Dunn's charges but strenuously denied any wrongdoing. Dunn, a Democrat who has taken the lead in the state's investigation of alleged price gouging by generators, said his committee had uncovered evidence that the ISO had asked state power buyers to purchase more energy than was needed last November -- setting up a "fictitious load" which would make it seem like the state needed more power than it was getting. The result, Dunn said, was to saddle California's power system with power bought at high market prices which the state was subsequently forced to sell at a loss. Dunn said the alleged deal was part of an ISO effort to cover up for "bad management" which left it unable to effectively monitor whether or not power generators were running their plants at minimum levels as required by federal regulators. Rather than fix their internal problems, Dunn charged that the ISO on some 30 occasions asked state power buyers to intentionally overstate demand in order to ensure that generators provided enough power to keep California running. Dunn said a taped telephone call between ISO staff and state power buyers allegedly discussing the unnecessary power purchases had been turned over to state Attorney General Bill Lockyer and the Federal Energy Regulatory Commission (FERC) for further investigation. Kahn of the ISO board said he had seen "no evidence whatsoever" that the ISO had sought to manipulate California's energy market, adding that the grid operator had done its best to prevent blackouts and ensure steady power supplies.

TransEnergie Starts Laying Cable

After a four-year running legal battle in two states, work has gotten underway on a high-voltage cable across Long Island Sound. TransEnergie is heading the \$130 million Cross Sound Cable project, which will run a 24-mile, 330 megawatt subsea cable from New Haven, Connecticut to Shoreham, New York. TransEnergie said it should take about 10 days to lay the cable, which it hopes to energize by June 20, just in time to meet the summer energy requirements of about 300,000 homes.