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Electric Transmission & Power Market Design.

California Market Design

BPA Chafes at CAISO's MD02 Plan

Says other western areas can't comply with mid-hour re-dispatch.

The Bonneville Power Administration has attacked several areas of the new market design (MD02) proposed on May 1 by the California Independent System Operator (CAISO), claiming that outside suppliers who sell power into California could suffer discrimination under new market features, like CAISO's planned ACAP obligation and the intended process for a day-ahead Residual Unit Commitment.

And BPA adds that out-of-area suppliers will fare no better under other ideas proposed by CAISO, such

as revisions to its 10-minute real-time imbalance market, plus a new mathematical price index designed for automatic mitigation for excessive wholesale power prices.

The problem, says BPA, stems largely from the fact that operators in other control areas in the Western Interconnection cannot achieve automatic generation control or dynamic scheduling across control area boundary lines. That means that outside suppliers lack the capability to comply with CAISO instructions *(See next page)*

Transmission Rollover Rights

Gens Fight SPP Over Grid Capacity

Dynegy sees battle as a symptom of an oversold network.

Power marketers Exelon Generation Co. and Tenaska Power Services have clashed with the Southwest Power Pool, alleging that SPP has refused without justification to honor requests to roll over certain grid rights under long-term firm service transmission contracts, as such rights are defined under the FERC's *pro forma* transmission tariff.

Yet the fight may be indicative of a larger problem.

Dynegy Power Marketing, for example, believes SPP either has oversold relevant flowgates or accepted other transactions that are not simultaneously feasible. It suggests that SPP

has turned to denying rollover rights to remedy the situation.

"Exelon will be irreversibly harmed by such denial because it will be deprived of the transmission service it needs to bring power from one of its generating resources to market," alleged Exelon's Noel Trask and attorney Michael Griffen (Morgan, Lewis & Bockius).

"SPP has not offered Exelon any reason why it would consider Exelon's rollover rights to be invalid."

The basic issue appears clear-cut. Does the promise of rollover rights in the *pro forma* tariff guarantee to customers an absolute right *(See page 6)*

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California Market Design

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for intra-hour redispatch. In fact, said BPA, suppliers outside CAISO lack even the permission to adjust mid-hour configurations, as western reliability rules don't permit such deviations.

"The term 'deviation' is a misnomer in this situation," explained BPA attorney Lara Skidmore, "because the import supplier is not deviating from the amount scheduled according to the practices of its control area.

"Rather," she explained, "it is the ISO that is deviating from the amount it knows the importer is obliged to deliver. It is inappropriate to penalize importers for their inability to follow these ISO dispatch instructions, and it is discriminatory for the ISO to impose 10-minute dispatch on resources that are unable to follow its instructions."

This problem will apply as well to CAISO's redesign of its 10-minute real-time market, which also requires mid-hour re-dispatch unavailable to imports.

"As a result," said Skidmore, "imports are paid the 10-minute price even when those prices are below the bid price."

That risk, she says, "makes the ISO real-time market less desirable than other West Coast markets, which have price certainty for sellers."

Of course, lately FERC has required importers to submit zero bids in CAISO's real-time markets, to act as "price takers." (See *GridWeek*, May 17,

CAISO's Proposed Price Cap Rule

Why BPA says it won't work for hydro.

As part of its MD02 market redesign, the California Independent System Operator has proposed to employ a new system after Oct. 1 (after FERC's west-wide price caps end) to test whether wholesale power prices are too high and to trigger price mitigation automatically.

The new test would create a new, 12-month rolling index of average monthly price markups to test whether prices qualify as "just and reasonable." (See *GridWeek*, May 17, 2002, pp. 6-7.)

But that proposal has won brickbats from attorney Lara Skidmore at Bonneville Power. She argues that California is so dependent upon summer imports of hydroelectric power as to make the new test unworkable.

Skidmore suggested that hydro imports from the Pacific Northwest play too great a part in California power markets to allow regulators to use such an index. According to Skidmore and BPA, erratic streamflows can play havoc with dispatch of higher-cost thermal generation, and skew forward gas prices to boot:

"The simple effect of hydro surplus during normal-to-wet years is to bring the real-time price down by increasing supply, particularly during spring runoff. A secondary effect is displacement of relatively higher-cost thermal generation, bringing spot gas prices down by reducing demand for spot market gas. Owners of these higher-cost generators are unlikely to commit to forward fuel contracts because of the likelihood in normal years that spring flows will provide enough generation to displace their output. ...

"During drought, these effects are reversed, with both power and gas prices increasing due to the greater use of higher-cost generation to make up for the lack of surplus hydro. ...

"This influence is prominent in the high-price periods that occurred in the ISO market in Oct. 1999, May 2000, and in the fall of 2000 when streamflow was less than expected ...

"If automatic mitigation is triggered simply by an increase in the average price, it may be inappropriately triggered by year-to-year fluctuations in hydro generation."

Source: Motion to Intervene and Protest of Bonneville Power Admin. regarding proposed Comprehensive Market Redesign," *FERC Docket Nos. EL00-95, ER02-1656, filed May 22, 2002.*

2002, p. 1.) BPA argues that that policy will make the situation all the worse.

"The requirement ... to reset

import bids to \$0 worsens this price risk because it increases the likelihood that the ISO will accept an import ▶



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California Market Design

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bid during low-price hours.”

The Trouble With ACAP

BPA's objections to the proposed ACAP requirement relate to the difficulties of real-time re-dispatch and CAISO's proposed penalty for failure of delivery.

Bonneville Power argues that generators seeking to export power to California will have trouble in offering energy to LSEs to satisfy their ACAP obligation. That's because CAISO's proposed ACAP structure would require all certified ACAP resources to respond to mid-hour ISO dispatch instructions, whereas other control areas in the Western Interconnection do not permit mid-hour redispatch of energy for other than system contingencies.

This problem, says BPA, “will discourage imports from providing ACAP and undermine the ISO's ability to assure adequate supplies.

“This is a substantive seams issue that the ISO has not addressed,” adds BPA, “despite [CAISO's] acknowledged dependence on imports to meet demand.”

Moreover, BPA feels that CAISO's proposed penalty for failure to deliver ACAP also would discourage participation by out-of-area generators during scarcity hours in the summer months. As an example, Bonneville notes how a curtailment of out-of-state ACAP due to forced outage of firm transmission in the source control area would trigger a penalty of about \$16.50/kW-month. The magnitude of that penalty, says BPA, would preclude importers from supplying ACAP.

(Note: As has been reported previously—see *GridWeek*, May 3, 2002, p. 1—CAISO to date has identified only the bare outlines of its Available Capacity [ACAP] obligation. It plans eventually to incorporate ACAP as

part of a long-term market redesign, but does not expect to have ACAP up and running by Oct. 1, when the FERC's west-wide price mitigation rules come to an end. Eventually CAISO intends for ACAP to function much like the installed capacity [ICAP] markets in the Northeast. CAISO would require all load-serving

The selection process would not always favor least-cost resources because the ISO remains concerned about renewed possibilities for “megawatt laundering” after FERC's price cap rules come off on Oct. 1. That strategy sees suppliers exporting power out of California and re-importing it in real time at exorbitant prices.

“Uninstructed deviations are created by the ISO ... the import supplier is not deviating ... rather it is the ISO that is deviating.”

—Lara Skidmore, BPA

entities to acquire sufficient ACAP to ensure adequacy of generation supply, with penalties imposed to enforce the obligation.)

Megawatt Laundering Resumes?

Pending full deployment of ACAP, and pending other redesign features that would integrate the day-ahead energy market with price-clearing for congestion management (locational marginal pricing), CAISO would impose a must-offer obligation plus a Residual Unit Commitment (RUC) process, to begin immediately after Oct. 1, when FERC's price caps come down.

But as with ACAP, BPA believes that CAISO's RUC process also will discriminate against out-of-state generators.

The RUC process as proposed would operate after the day-ahead market has cleared. CAISO would select a certain amount of capacity for the next day—95 percent of the forecasted “net short” load requirement. CAISO would select only 95 percent so as not to buy excess capacity. And it would select resources through a modified-but-not-quite least-cost solicitation protocol.

To discourage that, CAISO would force RUC resources to agree not to export power in the hour ahead of real time if energy is needed to serve control area load. It also would target “inertie” resources (external RUC resources slated for import into California) as the ones that would be backed off to get down to the 95 percent level. That is where BPA sees problems.

“By applying the upper limit on total energy at 95 percent of forecast,” BPA argues, “the ISO creates a bias that favors in-state resources over imports.”

This occurs, says BPA, even though the ISO intends in its base case to procure RUC power based on the economic merit order of bid prices.

“When the total energy ... reaches the upper limit,” notes BPA, “the ISO will selectively reject import bids ... and substitute higher-priced in-state RUC bids.”

Bonneville claims that it offered an alternative plan during the stakeholder process for CAISO to select also among internal resources to choose those to “back-off” to get below 95 percent, but complains that “the ISO has not addressed this issue or responded to [our] suggestion.” —B.W.R. **GW**

Grandfathered Transmission Agreements

NYISO Caught in Middle On Contracts

Rollover rights clash with regional tariff, affecting revenue distribution.

The New York Independent System Operator (NYISO) appears caught in the middle in a case that proves that preserving grandfather rights for old transmission contracts may be just as important for some ISO member-utilities as for the municipal or other transmission-dependent utilities that typically hold such rights and often oppose any amendments that would reform the contracts to ISO standards.

The case pits Niagara Mohawk (and a muni and a co-op) against New York State Electric & Gas Corp. (NYSEG). It poses several questions:

1) Whether a customer who has a grandfathered transmission contract with an electric utility that was signed before the ISO was formed can nevertheless extend the contract term even if regional ISO rules dictate termination on an earlier (original) date specified in the agreement;

2) Whether it makes a difference if the customer enjoys rollover rights separate from the ISO tariff;

3) Whether it matters whether those rollover rights are given in the contract itself or in the open-access transmission tariff (OATT) filed by the utility under FERC Order 888, to determine whether the rollover rights take precedence over the regional tariff.

Moreover, in a decision issued last September, the FERC added fuel to the fire by issuing findings that appear mutually inconsistent, relating to three separate grandfathered contracts.

On one hand, FERC said it favored a policy that would put private transmission contracts under the auspices of the regional ISO tariff as quickly as possible, and found that NYISO's regional tariff appeared to

dictate termination on the earlier dates for all three contracts.

On the other hand, FERC allowed an extension for one contract based upon rollover rights stated in the agreement, and for a second contract, it endorsed an informal letter order

“NYSEG’s attempt to invoke the NY ISO tariff to retroactively revise the grandfathered agreement is most outrageous.”

—George M. Pond (Hiscock & Barclay),
for Niagara Mohawk.

that allowed one short-term extension that appeared to violate that same clause in the NYISO tariff.

The grandfathered contracts call for Niagara Mohawk to wheel power for export from New York sources to the border with PJM. They involve PGE Energy Trading, American

“At stake is whether NYSE&G will receive a portion of the revenues.”

—Arnold H. Quint (Hunton & Williams) New York ISO

Municipal Power of Ohio, and Allegheny Electric Co-op.

Meanwhile, NYSEG claims that NYISO owes it a share of revenues from the wheeling transactions, because it believes that grandfather

rights for the Ni-Mo contracts have expired. NYSEG argues that transmission service provided the contracts should be deemed to have occurred under NYISO tariffs, which promise revenue distribution to NYISO transmission owners (TOs), including NYSEG (*See FERC Docket No. ER01-2736, pleadings filed thru May 28, 2002.*)

NYSEG sees the case as clear-cut. It argues that attempts by Niagara Mohawk (Ni-Mo) and its transmission customers to extend the life of the contracts violated “Attachment L” to NYISO’s regional tariff, which listed all pre-existing transmission contracts and specified the dates on which grandfathering would expire. It argues that grandfather rights for all three contracts expired automatically on the dates specified in Attachment L. Any retroactive bid to save those grandfather rights (whether by the parties or by FERC) would fail.

NYSEG has asked the ISO simply to generate bills and disperse revenues to NYSEG as if the service had been provided through the NYISO OATT.

“NYSEG has pursued the NYISO for over twenty months,” wrote attorney Robert Grassi (Huber Lawrence & Abell), representing NYSEG. Grassi said the ISO first appeared willing, but since has failed to turn over the billing information needed to calculate the embedded transmission service charge

used to allocate revenues from the export transactions.

“NYISO’s apparent uncertainty,” says Grassi, “can be settled once and for all and billing consistent with the NYISO OATT can be closed.” ▶

Transmission Agreements

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But NYISO remains wary of paying out funds without knowing for sure to whom they belong.

"The issue was not as simple as NYSEG would suggest," answers ISO counsel Arnold Quint (Hunton & Williams).

Meanwhile, Ni-Mo argues that if the grandfathered contracts themselves contain rollover rights, then those rights should prevail, even if the contracting parties omitted to cross every "t" and dot every "i" required by Attachment L in the course of crafting amendments to extend their agreements.

Ni-Mo sees NYSEG's attempt to invoke Attachment L as "outrageous."

Ni-Mo interprets the September FERC order as dictating that any rollover rights contained in a pre-existing contract must take precedence over a clause (*Attachment L*) in the regional ISO tariff that seeks to dictate the expiration of grandfather rights.

However, Ni-Mo believes that FERC intended for the regional tariff to take precedence if the rollover rights come not from the terms of the contract itself, but only from general provisions in the TO's company-specific OATT filed pursuant to Order 888.

AMP-Ohio labels NYSEG's motion as "little more than an untimely collateral attack on settled FERC actions."

Allegheny agrees: "NYSEG is not only completely wrong, but its theory is a gross distortion of the order."

"Such a holding is purely a figment of NYSEG's own wishful thinking."

Above all, the case shows that when pre-existing contracts are at issue, it's not only the customer who may have a stake in preserving the grandfathered contract. The utility TO may well have a similar interest.

—B.W.R. **GW**

Market Rule Tinkering

New England To Override Software

NEPOOL wants manual fix for AGC payments in high-cost hours.

Citing errors with software for real-time scheduling, pricing and dispatch (SPD) used by ISO New England (ISO-NE), the NEPOOL participants committee has proposed a manual fix starting June 1 that would override the software during high-cost hours (power price greater than \$100/

opposition, however. In particular, the Maine Public Utilities Commission charges that New England has broken faith with a promise to socialize RMR costs only as a short-term stop-gap solution pending eventual implementation of a congestion management scheme that is fully integrated with locational marginal pricing (LMP) for energy. (*FERC Docket No. ER02-1646, application filed Apr. 25, 2002, comments filed thru May 17, 2002.*)

"Because it is a manual fix, it will not ... need ... software reprogramming that could delay implementation of [the] standard market design."

—NEPOOL participants committee

Automatic Generation Control

Presently, Market Rule 7 compensates AGC providers for their lost opportunity costs based on a formula designed to capture the decrease in revenues, if any, experienced by a generator that is dispatched to provide AGC rather than dispatched as it would otherwise be to provide energy. AGC lost opportunity presently is calculated as the difference between the estimated desired dispatch point, which approximates the point at which the generator would have been dispatched had it not been used for AGC, and the real-time marginal price (RTMP) desired dispatch point, which is meant to approximate the point at which the generator providing AGC actually was dispatched by ISO-NE.

Nevertheless, NEPOOL points out that following periods in summer of 2000 when the energy clearing prices (ECP) were unusually high, certain generators providing AGC contended that the value calculated by ISO-NE for the RTMP desired dispatch point did not always compensate them fully. And on May 8, 2000, an arbitrator's ruling in favor of TransCanada confirmed those allegations.

Now, however, TransCanada ►

MWh) for calculations under Market Rule 7, which compensates generators when AGC protocol (automatic generation control) puts a plant outside its desired dispatch point.

A second proposed change (amending Market Rule 17, effective July 1) would create a mechanism for allocating monthly fixed capacity-type payments by ISO-NE to owners of RMR power plants (reliability-must-run) that must operate to assure proper grid function.

NEPOOL offered the first change (Rule 7) after an arbitration report supported TransCanada in a billing dispute with the ISO over AGC compensation, and TransCanada now appears to support the new rule, though it stops short of calling the change a perfect fit.

The second rule change has met

Market Rule Tinkering

(continued from page 5)

says it “strongly supports” the change proposed for Market Rule 7.

“Adopting the proposed rule changes is a nominal action that will help to keep resource owners from vacating the AGC market and instead restricting bids to the energy and reserve markets, or completely removing units from ISO dispatch by self scheduling,” TransCanada said.

TransCanada adds that proper calculation and payment of lost opportunity costs represents an implementation of a fundamental economic principle—one that provided the basis for FERC’s recent order extending opportunity costs payments to the non-spinning reserve markets. (*See Docket No. ER02-1149, 99 FERC ¶ 61,124, Apr. 26, 2002*).

Nevertheless, TransCanada says the change is not quite a perfect fix, because it does not actually fix the software. Instead, the correction simply pulls the plug on the computer during those hours in which the software appears not to work.

NEPOOL counters that its resources are now “taxed” in making system changes to accommodate a new standard market design and prefers not to initiate any major system modifications.

Must-Run Compensation

The proposed change to Market Rule 17 would provide a new method to allocate the fixed monthly costs that ISO-NE pays to RMR plants, after Sithe New Boston sought special compensation in the form of cost-based capacity-type payments and FERC ruled that the ISO could adopt a temporary stop-gap method to bill market participants to raise the money.

The FERC-approved allocation method converts the monthly fixed-cost charge paid to Sithe to a per-hour fixed cost charge to be allocated

“The proposed rule changes will help to keep resource owners from vacating the AGC market ... or completely removing units from ISO dispatch by self scheduling”

—Jennifer Nichols, counsel for TransCanada

among participants based on their network load or reserve capacity in that hour. The change proposed by NEPOOL would formalize that arrangement as a generic rule applicable to any RMR plant.

But the Maine PUC argued that NEPOOL’s proposed changes may become too permanent.

“The PUC does not object to the socialization of such fixed-cost contracts until LMP implementation, but strongly protests the continuation of such socialization after LMP implementation,” it said.

Instead, the PUC asked FERC to approve the cost allocation method only on an interim basis—until the ISO implements congestion management with LMP as part of a new standard market design.

Also, the PUC asked FERC to require a sunset provision and a new allocation method that would assign

the RMR costs only to those parties that cause the congestion.

It wants that cost allocation method filed on or before Nov. 1, 2002 to provide a reasonable period for consideration of the new method prior to the expected implementation of LMP in January 2003.

Meanwhile, Northeast Utilities Service Co. (NUSCO) on behalf of its five utility company affiliates, and joined by affiliated power marketer, Select Energy, support amendments to market rule 17. They said the proposed allocation method will allocate monthly fixed capacity-type costs across the NEPOOL control area to transmission customers based on each customer’s network load and reserved capacity. That, they said, will allow the capacity payments made under mitigation agreements to be allocated to transmission customers just like other transmission system costs. —L.A.B. **GW**

Transmission Rollover Rights

(continued from page 1)

to extend existing service rights as is? Or, does the provision simply function as a tie-breaker, applying only when a competing customer vies for the same rights, and then ensuring that the incumbent gets priority?

Exelon and Tenaska, supported by Dynegy, take the first side. SPP takes the second. (*See Docket Nos. EL02-86-000 (Exelon) & EL02-89 (Tenaska), pleadings filed thru May 22, 2002.*)

No Capacity, No Service

Exelon complains that in March it

asked SPP, effective June 1, to roll over 400 MW of existing, long-term firm point-to-point service from Central & South West (CSW) to Entergy, and that SPP reported back on April 18 that it lacked sufficient transmission capacity to honor the request as stated (construction of network upgrades needed to go forward would take 12 to 36 months), but could provide 226 MW of the requested capacity if Exelon would agree to curtail other long-term firm service (from CSW to Ameren) for the duration of the summer. ►

Transmission Rollover Rights

(continued from page 6)

Otherwise, said SPP, it would have zero available transmission capacity (ATC) on the CSW-to-Entergy path.

Tenaska, too, said SPP demanded curtailment of another transaction before honoring rollover rights (in that case some 9 MW of capacity from CSW to the ERCOT East DC Tie).

What Price a Rollover?

The parties focus on what FERC intended in its *pro forma* open-access transmission tariff (OATT) by ensuring rollover rights for contract holders.

“Requiring an existing transmission customer to pay for system upgrades to retain its current level of service effectively eviscerates rollover rights,” wrote attorney Neill Levy (Kirkland & Ellis), representing Tenaska.

Tenaska acknowledged that a transmission provider can deny rollover rights for long-term service if the capacity is needed to meet the transmission provider’s native load growth. But then the provider still must include specific language in the service agreement to deny rollover rights because such capacity likely will

“Nothing permits SPP to [condition] rollover service on curtailment of the customer’s other confirmed firm services.”

—Exelon

be needed to meet reasonable forecasted projections of native load growth. That language was missing in these cases.

Exelon added that according to several FERC orders, an existing customer who takes long-term firm service retains rollover rights if he agrees to match the rate and term offered by a competing customer.

Yet SPP countered that the rollover right is more a tiebreaker than an entitlement—that rollover rights in effect do not exist absent a competing service request requiring a finding as to priority.

“What Exelon is attempting to do is turn a reservation priority over competing requests for firm transmission service into an absolute right to firm transmission capacity, for an indeterminate period regardless of the requirements of section 2.2 and without regard to the resulting effects of the service extension on the transmis-

sion system and existing firm transmission customers,” it said.

According to SPP, an existing customer is not granted service in perpetuity, nor guaranteed that the amount of capacity available for renewal of its service will not be affected by other previously approved, noncompeting service requests, the need to meet growth in the native load served by the transmission provider, changes in transmission system topology, loop flow impacts due to changes in transactions on other transmission systems, or redispatch.

SPP, in fact, believes it did act exactly per the rule:

“Upon evaluation of Exelon’s service renewal, SPP determined that there were no requests substantially similar in all aspects, therefore, section 2.2 [the rollover right] does not apply,” SPP said.

Thus, it added, the request was evaluated the same as any (See page 11)

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Slicing & Dicing

State Estimators Come of Age

Software moves from “iterative” to “global” to measure flows on the grid.



Lori A. Burkhart, Editor

Eric Freeman, vice president and general manager of EleQuant,* has an answer for the U.S. Dept. of Energy, which has called for more accurate tools to analyze power grid flows in real time. And the beauty is, there is no wait. EleQuant has a product on the market right now, and Freeman is not bashful about letting you know it.

“Many electric utilities have been operating in the dark with regard to the actual understanding of their grid in real time,” Freeman says.

“A new technology like ours enables them to see things very clearly.”

Of course, calculating load flow is nothing new. Ever since the 1960s, utilities have used an iterative mathematical model called Newton-Raphson to calculate load flow. That method is still used today. It “works reasonably well most of the time,” Freeman notes.

But merchant power has put the squeeze on grid capacity of late, making real-time data more important.

EleQuant believes it has met that need with its new software suite called AGORA. Freeman called it a “new mathematical approach.” It lets grid operators “see their networks with a clarity and reliability never before experienced,” he believes.

“And it works all the time—in good conditions and in bad—all the way up to voltage collapse.”

Think about walking along a cliff on a foggy night, he says, and having to back off a fair distance for good measure.

“If it is crystal clear, you can walk right up to the edge and not go over, that is what our software represents for these operators.”

A Well-Kept Secret

As Freeman put it, the problem with the traditional load-flow measurement is “one of the best keep secrets” in the power industry.

“No one likes to talk about it because it’s like airing dirty laundry.”

If you agree that a state estimator should be able to measure network flow every few seconds, he says, then “perhaps three utilities” in the U.S. have state estimators that function.

“The problems are not so bad under normal conditions, but the likelihood of actually getting the wrong solution as you approach voltage collapse increases, and ironically that is the moment when you need accurate measurement more than ever before,” Freeman adds.

Transmission operators must calculate load flow equations, and some parameters come from signals that come into load control centers, but some values must be estimated. To do that, says Llopis-Rivas, a conventional model like Newton-Raphson will begin with an initial state estimate. They then will calculate small incremental

steps available to improve power flows, until the margin for improvement becomes infinitesimal. At that point you’ve found the final solution. It’s like using integral calculus to compute the area under a curve.

Even so, she notes, you can run the Newton-Raphson model in multiple reiterations and your results won’t always converge.

“Sometimes it converges to a wrong solution and sometimes it doesn’t converge when you do know that you have a solution,” she explained. Also, the problem arrives more frequently when your initial base case is inaccurate.

“This is a matter of craftsmanship for most engineers in the electric utility business doing planning analyses” in the boundaries of voltage collapse, she noted.

By contrast, she says, AGORA is not an iterative process. You don’t start with a base case.

“You get the solution, and you always get (See page 9)



Regina Llopis-Rivas



Eric Freeman

“It works all the time—in good conditions and bad—all the way up to voltage collapse.”

—Eric Freeman, EleQuant, Inc.

Patent Pending

And another product waiting in the wings ...

In addition to the AGORA suite offered by EleQuant, another commercial-grade software application that moves away from iterative models to track real-time load flow on the transmission grid is AempFast (Advanced Energy Management Power Flow Analysis and System Technology), developed by Optimal Technologies (www.otii.com).

As explained by CEO Roland Schoettle, AempFast employs a “proprietary N-dimensional” (nonlinear) global optimization model. Schoettle adds that his software makes no approximations and can solve any problem that can be modeled as a network. Schoettle’s company has coined the term “QuixFlow” to describe its optimization model.

When he talked with GridWeek, Schoettle repeated the same basic points offered by Freeman and Llopis-Rivas at EleQuant—that traditional iterative load flow models suffer from the fact that they don’t give repeatable solutions in multiple runs.

“Our competitors make huge approximations and assume that the system is linear,” says Schoettle.

“We conducted our first robust test in 1997. One competitor took 24 hours for one run of their program. We were repeating the same number over multiple 30-second runs.

“Our mathematical approach is different. Our algorithm produces repeatable findings and works on a global basis.

And our competitors can’t run their applications on large systems with too many nodes. State of the art is 15 buses—we can do it for 20,000 buses.”

We asked Schoettle about FERC’s initiative on a standard market design, and whether he had given any thought to the fact that many RTO developers are suggesting obligation-type transmission rights, as opposed to option-based rights, because of ease of modeling.

“We have not addressed the problem of option-based FTRs, said Schoettle. “But our software allows us to rank objectives. It should be easy enough.”

We asked Schoettle whether AemFast was available yet.

“It’s commercial grade right now,” he answered, “but we can’t sell it yet. Our patent application is still pending.

We’ll have to go through quite a long vetting process before people will trust us.’

“We know we can run it. But we still have to walk through the fire.” — B.W.R

Software

(continued from page 8)

the right one—you never get a wrong one. And when there is a solution, you find it.”

Freeman boasts that AGORA can give utilities a leg up on the competition.

“No one other than PG&E in the U.S. has a tool like this,” Freeman said.

A Test Run in California

Llopis-Riva says the California ISO approached her and asked for an analysis of what AGORA would have recommended during the 12-hour grid outage that occurred in the San Francisco Bay area in December 1998. The result was “surprising” she said, in that AGORA would have cut the restoration time in half. That analysis came to the attention of PG&E, which decided to send engineers to Spain to see AGORA working for real by Spain’s national grid operator, Red Electrica de España.

PG&E has since become EleQuant’s first U.S. AGORA client.

(Freeman notes that some companies are running up to three years behind schedule to get a state estimator on line. Yet he claims that AGORA takes only two months to install and deploy, at between \$2 to \$5 million per site, depending on grid size and desired functions.)

Freeman adds that when EleQuant proposes to demonstrate AGORA, as it offered for EPRI, “you’ll see ten or twelve electric engineers smile and say it’s too good to be true, show us how it works.”

Yet Freeman argues that AGORA always gives the correct physical solution and allows operators to improve performance on three key functions: (1) monitoring the grid, (2) restoring the grid, and (3) simulating the grid.

“Our hope is that operators and planners alike will use the same technology platform for their job functions,” he says. Freeman adds that up to now that has been impossible.

“Planners are always out of synch with the real-world because they are always working on a model that existed a year or two ago and may or may not have fictitious ▶

Software

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elements to make them work.”

For example, Freeman observes that a typical utility will have a couple of big thick binders on the shelf for restoration plans—what to do if two generators and a transmission line go out.

But electrical grids are dynamic, he adds, so it is very hard to have static plans in place for contingencies.

“It’s almost too much to get your arms around, the fact that this is always accurate, always reliable all of the time.”

That, says Freeman, allows engineers to monitor each individual line down to the breaker level and generates those graphics automatically.

“This is something as a software developer we think is very basic, but it enables us to catch the attention of

engineers and yet is something they can relate to, because many big utilities still hire college students to come in during the summer and draw diagrams by hand.”

Yet, despite the allure of graphics, Freeman says EleQuant has focused its marketing campaign mainly on accurate bean counting.

“It’s not a product attribute we focus on...its like automatic door locks on a Porsche, that is nice but not the biggest feature.” —L.A.B. **GW**

** EleQuant, Inc. is the wholly owned U.S. subsidiary of Grupo AIA, based in Barcelona. Both were founded by Regina Llopis-Rivas, the president and CEO. Llopis-Rivas began Grupo AIA fifteen years ago in Barcelona as a research and development consulting company employing mathematicians and physicists. She holds a doctorate in advanced mathematics from Cal-Berkeley.*

News Briefs

Companies

● **ComEd + PJM.** Commonwealth Edison announced on May 29 that it will join the PJM Interconnection as part of a proposed independent transmission company (ITC) to be formed between ComEd, American Electric Power and Illinois Power (each a former member of Alliance GridCo). National Grid would manage the new ITC, which would operate under the PJM umbrella. “We believe that PJM is the best option for our company and our customers,” said Betsy Moler, a senior v.p. at ComEd’s parent company, Exelon, and former chair of FERC. Moler believes ComEd customers will enter into a mature market more quickly with PJM than with MISO. The move also would put all of Exelon under the PJM market. As Moler explained, “PJM has market structures already in place that are similar to what FERC is proposing in its current standard market design.” Moler added that the former Alliance companies had spent over \$70 million to develop infrastructure needed to create an

RTO and that “continuing as an ITC, while under the authority of the PJM, allows us to use these existing systems to the maximum extent possible.” (*GridWeek* had reported earlier—Apr. 19, p. 4—that Alliance wanted somehow to “capture the value” of its heavy investment in computer and software systems.)

Deals

● **Transmission Service Access.** Duke Energy Trading and Marketing reached agreement with Entergy to settle their dispute over access to firm network transmission service to allow the City of North Little Rock, Ark. (a 50-year customer of Entergy, successor to Arkansas Power & Light Co.) to take buy energy from a non-utility supplier. (For more, see *GridWeek*, Apr. 26, 2002, p. 4.) Entergy argued that regardless of whether the city was entitled to rollover rights under the 1994 power agreement (as Duke argued) or whether it waived those rights in 1998 (as Entergy argued), the system impact studies showed that long-term network

service was available. (See FERC Docket No. EL02-75-000.)

Investigations

● **California Power Procurement.** The Board of Governors of the California ISO has created a special committee to investigate transactions conducted between the ISO and the California Dept. of Water Resources. The committee will hire an independent investigator to look into the transactions with DWR’s energy scheduling group. That includes some 30 transactions called “questionable” by state senator Joe Dunn, who suspects that the ISO miscalculated how much electricity was needed to keep power flowing across the grid, and told DWR to buy high-cost electricity that the state later sold for a loss.

Tariffs

● **Generation Interconnection.** Though it accepted PJM’s proposed tariff with new terms and conditions for generation interconnections, FERC said it would not dismiss a related ▶

Transmission Rollover Rights

(continued from page 7)

new request for transmission service.

"The capacity Exelon wants has not been provided to competing new customers," SPP added for good measure.

Dynegy Power Marketing agreed with Exelon, however.

"Exelon's complaint raises valid objections against SPP's rollover practices that warrant the FERC's scrutiny," said Dynegy.

If the Exelon complaint is not granted, Tenaska added, "transmission providers will be in a position to build their transmission systems on the backs of incremental point-to-point transmission customers."

In fact, Dynegy questioned whether SPP had acted in good faith.

"SPP seems to have accepted other competing requests that will indeed award rollover capacity to competing

customers prior to the deadline, thereby depriving existing long-term point-to-point transmission customers of OATT-mandated rollover rights," said Dynegy.

Dynegy said it is experiencing the same problem with SPP, and it has engaged to no avail in multiple conversations with SPP in an attempt to resolve its own rollover issue.

—L.A.B. **GW**

News Briefs

News Briefs

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complaint by Old Dominion Electric Co-op. (ODEC) until after it has issued its final rule in *Docket RM02-1*. ODEC plans to build a new power plant in Rocky Springs, Md., to interconnect with PJM member PECO Energy, and has disputed paying for network upgrades, even though PJM would give back transmission rights commensurate with the increase in system transfer capability (instead of credits against transmission charges).

ODEC argues that the arrangement (paying both for upgrades and grid service) violates the FERC rule against "and" pricing for transmission. (*Docket Nos. EL01-106-000 and ER02-1333-000, 99 FERC ¶61,188, May 17, 2002.*)

Studies

● **Distribution Sector.** XENERGY Inc. on May 29 released a study finding that the electric retail distribution business of the future may take widely diverging paths, running

from a technology driven "wires.net" model to a "Sam Walton" image that focuses on cost-cutting and outsourcing. The paper, "Crossed Wires: Scenarios for the Future of the Electric Distribution Business," analyzes the forces that will shape distribution companies. They are: (1) regulatory oversight; (2) earnings growth; (3) infrastructure investment; (4) technology changes; (5) asset management; and (6) reliability pressures. See www.xenergy.com. **GW**



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