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Eastern Wisdom … or Wild West?

Electric reliability. For utilities, nothing is more important. But it's the one thing that the guru's of deregulation have not quite figured out. We know we need a reserve of power. But when reserves grow too large, power plants lose their value. Merchant generators can face ruin. Can we have our cake and eat it too? In this issue we offer two views on the matter: One from California, the other from New England

Bruce W. Radford, Publisher

RELIABILITY

Market Design Still Eludes California …

By Bruce W. Radford

If reliability for electric utilities is job #1, then California wants you to know it hasn't forgotten.

And so the state's most put-upon bureaucracy, the California Independent System Operator (CAISO, for short), has proposed as part of its comprehensive new market design to impart a regime for electric reliability that includes multiple sets of both belts and suspenders. The regime appears so arcane that even CAISO has seemed at a loss at times, some say, to describe how it might work.

One key idea, known as "RUC" ("residual unit commitment") seems to serve no obvious market purpose. Another concept, known as "MOO," later morphed into "FOO" ("flexible offer obligation"). These ideas were born of fear of the state's power crisis of 2001. They were designed to ensure a forever-reliable supply of electric generating capacity. But detractors say "phooey." To them it's just paving the cow path.

The full proposal, known as "MD02" (Amendment No. 44 to the ISO tariff), must eventually win approval from the Federal Energy Regulatory Commission (FERC). Indeed, FERC already has forced compromises on the parties, leading CAISO to announce significant modifications as recently as February. But as of early March, CAISO had failed to adjust its proposal to mesh with an order issued in January by the state Public Utilities Commission (CPUC). As a result, CAISO's MOO, FOO, and RUC now seem redundant. »

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In fact, state PUC president Michael Peevey found it necessary to write to FERC chairman Pat Wood on March 3, on the first day of a conference held in San Francisco to air public concerns, to complain about FERC's efforts to transform CAISO's RUC process into something different.

"I continue to be concerned," wrote Peevey, "with the direction in which FERC seems to be headed on issues such as the Residual Unit Commitment."

Peevey advised Wood that FERC's pushing and prodding would introduce a "perverse bidding incentive" into the day-ahead energy market proposed by CAISO as part of its new market design.

Yet hopes were high last year at the start. Many in California, it was said, had come to accept "the wisdom of the East." They had begun to understand how grid operators in the eastern U.S. (like the PJM, New York, and New England ISOs) had introduced financial tools to solve physical problems.

In early drafts, in fact, CAISO itself had endorsed the concept of a security-constrained dispatch flowing from competitive bids, including locational marginal pricing (LMP) in the MD02 to resolve troublesome grid congestion, and drawing praise from no less a market guru than Harvard professor William Hogan. *(See Amendment to Comprehensive Market Design Proposal, FERC Docket No. ER02-1656, filed July 22, 2003.)*

But by late this winter, things had begun to go awry. In a series of public conferences, opponents had attacked the market design as too heavy-handed. And it took only four weeks after opponents had ripped the FOO and RUC concepts, at a meeting in Washington, D.C. in late January, for CAISO to flip-flop. In an amendment issued Feb. 24, CAISO announced a brand new RUC regime. To be fair, FERC had virtually forced CAISO into this retreat with an order issued last October. *(See Docket No. ER02-1656-003, Oct. 28, 2003, 105 FERC ¶61,140.)* The Feds were trying to steer the ISO's reliability provisions into a tighter linkage with programs in place in the eastern ISOs, which have tended to adopt capacity markets (so-called "ICAP" programs) to assure a supply of power. But CAISO's move only gave the impression that it was lurching from one public relations crisis to another, re-inventing the design on the fly, and would likely propose new iterations in the future.

Don Garber, the author of that "wisdom of the East" phrase, who works as a staff attorney for Sempra Energy, had suggested in February that CAISO still showed a bias toward physical solutions. He felt that California stakeholders as a group needed help in "re-conceptualizing" the problem in order to escape "the prison of the past." In his view, the state was strangling in "regulatory duct tape." California, he implied, needed to show a willingness to adopt the sorts of financial tools common to the eastern ISOs. Such tools, Garber says, "lie at the heart of any electricity market."

Instead, as he complained, any attempt to incorporate financial bidding tools into the MD02 proposal had become the "third rail" of MD02 politics: "Touch it and you die." »

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Many in California had come to accept the "wisdom of the East." But financial bidding tools remained like a third rail: "Touch it and you die."

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To better understand the situation, compare the proposal filed March 1 by the New England ISO, to implement a locational ICAP plan. *(See, FERC Docket No. ER03-563-030.)* The New England plan calculates an approximate market value for electric capacity, separate and apart from energy. Using a single model, it allows for different valuation inputs, depending upon which of four sub-regions regions plays host to the plant. *(See sidebar "New England Gets It Right?")*

As with other ICAP plans, the New England program seeks to create a financial market for electric capacity as a product separate from energy. And like the New York plan (See "New York Throws a Curve," *Public Utilities Fortnightly*, May 15, 2003, p. 25), the New England plan employs a sloping demand curve so that capacity market prices remain more stable and do not "fall off a cliff" when reserve supplies exceed desired levels.

Yet the New England plan differs from New York in a key manner. Rather than "penalizing" utilities through a deficiency charge, which likely will not *(Continued on p. 5)*

…New England Gets It Right?

The proposal issued March 1 by the New England ISO to create a market for electric generating capacity dependent on the location of the power plant — the locational ICAP plan — marks a scientific attempt to approximate the true capital cost of a new power plant.

Moreover, the locational ICAP plan can be also viewed as an alternative and substitute for the CAISO FOO and RUC rules discussed above.

The New England plan builds on the basic concept fleshed out earlier in New York. That plan set up a more-or-less arbitrary deficiency penalty charge keyed to a sloping demand curve, payable by utilities if their supply portfolio runs too short. The sloping demand curve avoids the "binary" all-or-nothing-world of capacity pricing. Under the New York system, capacity prices do not simply "fall off the cliff" and collapse to near-zero when reserves of installed capacity reach the desired point. (For a description of the New York plan, see, "New York Throws a Curve," *Public Utilities Fortnightly*, May 15, 2003, p. 25.)

But the New England plan goes New York one better. It attempts to derive a market price for capacity that exactly mimics the avoided-cost value of a new plant. It examines typical fixed-cost values for simple-cycle gas turbines on the margin. The derived price thus serves as a one-for-one incentive for new construction.

The New England regime also includes a formula that takes into account the degree to which a turbine owner might expect to earn energy revenues during a typical year to cover some (but not all) of his fixed costs.

By including a credit offset for expected variable revenues, the New England plan hopes to avoid making an incentive by the capacity price too high. Also, the plan sets up four sub-regions, and performs a different calculation setting for each area, so that locational advantages are reflected in the capacity market price.

In essence, the capacity market consists of a pre-determined price, derived from the sloping demand curve. Electric utilities and load-serving entities (LSEs) are required to assemble energy portfolios of sufficient capacity. As the amount of power surplus changes in New England, the sloping demand curve indicates the price the utilities and LSEs will be required to pay to assure the appropriate capacity reserve. The price paid then serves as an incentive to power producers to construct new capacity. (See Compliance Filing of ISO New England Inc., *FERC Docket No. ER03-563*, filed Mar. 1, 2004.)

The following seven-step schematic and accompanying graphics illustrate the mathematical process in abridged form:

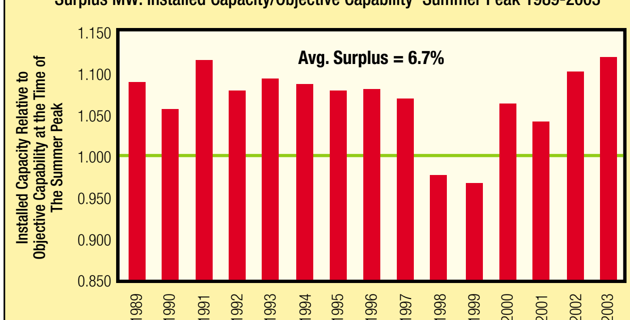
How to Plot an ICAP Demand Curve in Seven Easy Steps.

1. Supply Surplus

Determine the extent of any power supply surplus. Calculate "objective capability." (OC = peak demand requirement + required reserve.) Compare actual installed capacity vs. OC. For the period 1989 – 2003, ISO-NE determines that the ISO region experienced an average real surplus of 6.7%, or 1.067 times the OC. *(See Figure 1.)* »

Figure 1: Surplus Capacity in New England, 1989-2003

Surplus MW: Installed Capacity/Objective Capability *Summer Peak 1989-2003



*Note: "Objective Capability" (OC) denotes peak demand requirements plus a planning reserve. Thus, an amount of "installed capacity" (IC) in excess of objective capacity represents a surplus. The period in question shows an average of 1.067 in terms of IC/OC, representing an average surplus of 6.7 percent.

Source: Compliance filing of ISO New England, FERC Docket No. ER03-563-030, Mar. 1, 2004.

2. Gas Turbine Fixed Cost

ISO-NE estimates the levelized average annual fixed cost of a simple-cycle gas combustion turbine at about $80/kW-yr. *(See Table 1.)* That value is equivalent to about $6.66/kW-month, which, as it turns out, is also the value of the capacity deficiency penalty charge under the ISO's prior (current) nonlocational ICAP plan.

3. Gas Turbine Energy Revenues

ISO-NE estimates that over the period from the second trimester of 1999 through 2003, that on average, a gas turbine returned $25.20/kW per year (rounded) in operating energy revenues to turbine owners. *(See Table 1.)* On a monthly basis, $25.20/kW-yr is equivalent to $2.10/kW-month.

4. Maximum Effective Reserve

ISO-NE determines that a real supply surplus of greater than 18% (1.18 x OC) does virtually nothing to improve reliability. It decides to assign a capacity value of zero when installed capacity reaches 1.18 x OC.

5. Nominal Demand Curve

Plot a straight-line linear function (the sloping demand curve) on an x-y-coordinate graph, so as to intersect two points. One point of the curve is where x (surplus capacity) = 18%, and y (price) = 0. A second point is defined where x = 1.067 (the actual 15-yr. surplus) and y = $6.66/kW-mo. (the assumed nominal value of capacity). (See Fig. 2.) The points on the curve denote the nominal market (ICAP) price of capacity at different levels of surplus (subject to locational adjustment).

6. Credit for Energy Revenues

Plot a new point on the same graph at the point where x = 6.7 % surplus, but y = $4.56. (The figure of $4.56/kW-mo. = the nominal capacity price of $6.66/kW-mo. where surplus = 6.7%, minus the revenues of $2.10/kW-mo. [*see Step #3*] that a turbine owner can expect to earn from energy sales.)

7. Final, Scarcity-Adjusted Demand Curve

Draw a new linear demand curve through the new point established in Step #6, and the point used in the tentative demand curve (*Step #5*), where x = 18% and y (price) = zero. This new line will appear on the graph as if "pivoted" downward and counter-clockwise, from the nominal curve shown in Step #5 and Fig. 2.

TABLE 1: OPERATING REVENUES FOR GAS TURBINES[1,2] MAY '99 – DEC '03

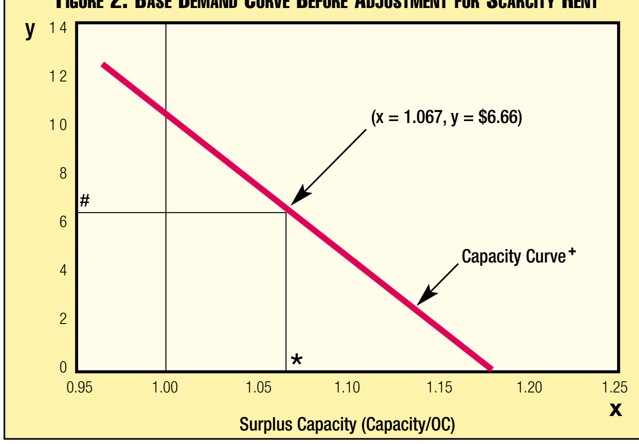
Infra-Marginal Revenue ($/kW)			
	Months	Combined Cycle[3]	Combustion Turbine[4]
1999	8	$ 58.43	$ 27.68
2000[5]	12	$ 69.57	$ 18.04
2001	12	$ 90.09	$ 40.32
2002	12	$ 73.14	$ 21.20
2003[6]	12	$ 71.30	$ 10.31
Annual Average	**56**	**$ 77.69**	**$ 25.19**

Estimated Levelized Fixed Cost ($kW-yr)		
	Combined Cycle	Combustion Turbine
Annual	$100 - $130	$60 - $85

Notes to Table.
1. Estimated infra-marginal energy revenue for hypothetical new units. Assumes that all units at bid marginal cost and sell their full in-merit output (relative to their zonal price) into day-ahead or real-time markets.
2. Calculated at 90% of maximum to account for forced outages and other operational limits (e.g. start-up times, minimum run times, etc.)
3. Based on heat rate of 6,800 BTU/kWh and variable O&M costs of $2/MWh. Analysis uses daily gas prices for New England.
4. Based on heat rate of 10,500 BTU/kWh and variable O&M costs of $3/MWh.
5. Energy prices capped at $1000.
6. Months subject to Standard Market Design (SMD, March to Dec. 2003), calculated based on real-time prices for New England Hub.

Source: Compliance filing of ISO New England, FERC Docket No. ER03-563-030, Mar. 1, 2004.

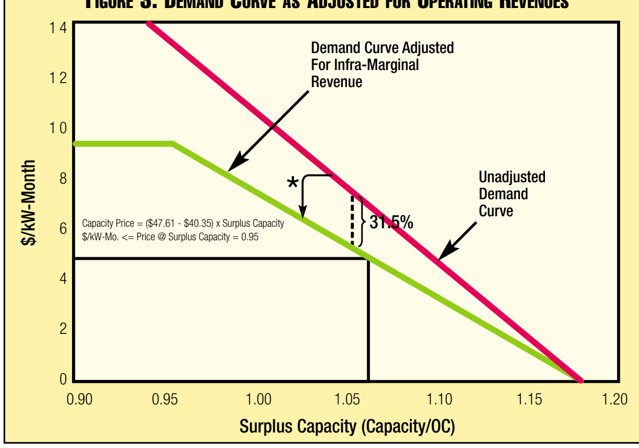
FIGURE 2: BASE DEMAND CURVE BEFORE ADJUSTMENT FOR SCARCITY RENT



Source: Compliance filing of ISO New England, FERC Docket No. ER03-563-030, Mar. 1, 2004.

Notes.
* Value of 1.00 denotes zero surplus. Value of 10.67 denotes New England's historic 6.7% surplus (*see Fig. 1*). Value of 1.18 denotes an 18% surplus (a surplus any larger does not improve reliability in a useful way). # Price of $6.66/kW-month equals deficiency charge assessed for lack of capacity under current ICAP plan for New England (plan in effect before addition of demand curve). + Deficiency price is capped when capacity falles to 95% of Objective Capability (x = 0.95 or less).

FIGURE 3: DEMAND CURVE AS ADJUSTED FOR OPERATING REVENUES



Source: Compliance filing of ISO New England, FERC Docket No. ER03-563-030, Mar. 1, 2004.

Notes.
* This downward "pivoting of the capacity demand curve reflects a credit for the revenues that planty owners earn from operating a gas turbine. (Price at 1.067 of capacity needs is adjusted downward by $2.10, from $6.66 to $4.56 ($2.10/kW-mo. = $25.20/kW-yr. [see Table 1] divided by 12 mos.

California

(Continued from p. 3)

help relieve the physical shortage, the New England market is set up to elicit a price for capacity that is calculated specifically to create an incentive to encourage plant construction. In short, the New England plan appears to represent the very latest and most developed theory in the eastern pantheon of the standard market design (SMD).

Back in California, it remained to be seen whether CAISO's latest concessions, offered in its Feb. 24 modifications, would win acceptance by stakeholders and those attending the technical conferences. Of course, FERC's order of last year was "advisory" only. It was not binding, though CAISO thus far has appeared largely willing to bend on FERC's demand.

Even so, CAISO's plan and its latest modifications must be taken still as a work in progress.

MOO, FOO, and the Gen Mix

CAISO's MD02 plan would create a day-ahead energy market, as in the Eastern ISOs, but it would also include a raft of elements unique to California, such as an hour-ahead energy market (in addition to a real-time, five-minute market), and CAISO's proposed RUC process to ensure reliability of power supplies. It includes some features created and left over from the days of the now defunct California Power Exchange, when CAISO and later FERC imposed price controls and a must-offer requirement, in the wake of the summer 2001 power crisis. Those features today still cap energy prices at $250/MWh, and force power producers to offer supply into the real-time market.

So the question now is whether this tangled combination of ideas, old and new, will end up working at cross-purposes. Two factors bear heavily on the answer: (1) California's net power deficit, which forces the state to rely heavily on out-of-state power imports; and (2) the state's generating mix, which features a portfolio heavy on "constrained output generators," (COGs). Those COGS include hydropower units, which must operate subject to finite stream flows and rules for water resource management, and gas turbines, which often must obey restrictions on hours of operation, owing to limits on air emissions.

The importance of generating mix reveals itself in the way these plants must respond in operation to the CAISO's reliability regime. By making the regime heavily dependent on a physical solution — a must-offer rule that requires owners to physically commit their plants — the market design tends to increase the need for start-ups, ramp-downs, and minimum-load operation. This result imposes costs.

In this analysis, the hydro units qualify as quick-starting, but they prefer to bid in the hour-ahead (HA) market, rather than DA, because of problems scheduling water usage. The turbines, however, don't want to exhaust their limited run times too far ahead of peak, and so also might well prefer to bid HA or even real-time. They don't want to be dispatched for an hour at midnight, or at 3 am.

According to Reliant Energy, a certain segment of the mix (a dozen or so units, 500-700 MW per unit) qualifies as slow-starting. They prefer to bid DA, and cannot easily tailor bids to the HA or RT timeframes. For them, the FOO rule offers little real flexibility, yet is not particularly onerous, as long as they recover their startup (SU) and no-load (NL) cost, without CAISO denying recovery by netting those costs against energy revenues from an actual dispatch.

California's original must-offer requirement applied only to the real-time market. But CAISO proposed last July to expand it to cover day-ahead bids and gave this plan a new name, "MOO" (must-offer obligation). As a compromise, FERC in its Oct. 28 order advised CAISO to revise the MOO so as to give power producers the flexible option (FOO) of offering supply at least either day-ahead or real-time. CAISO has since continued to endorse FOO as a key element of its market design. It defines FOO as a sort of market mitigation technique: it serves to prevent a physical withholding of power supplies before the fact.

RUC, Markets, and Distortions

The RUC process has no obvious eastern analogy. CAISO describes it as a reliability "backstop," designed to assure a supply of energy in real time, even if short in forward markets. FERC would rather think of RUC as a capacity market — as a western version of eastern ICAP plans.

Under the RUC plan, CAISO would conduct the day-ahead auction, and then investigate after the fact whether the DA market has cleared so as to schedule a volume of load equal to what CAISO believes is the likely real-time demand. If not, CAISO would put a sort of "hold" on an additional increment of resources, in merit order based on their bids in the DA market. That hold would entitle the plants to receive an "availability" payment. It would also force the units to be available in real time, so that CAISO could call them if needed, at some certain energy price.

At first, CAISO wanted a right to rescind the availability payment if the plant was later dispatched for energy, and to pay for that energy at the as-bid price. Later, under urging from FERC and stakeholders, CAISO agreed not to rescind the availability payment, and to call the energy at the DA market-clearing price. As of the technical conference in Washington, D.C., in late January, it was still unclear if CAISO would allow "RUC'ed" plants to export energy out of state in a bilateral energy sale, prior to real time. The whole RUC process would be repeated after the hour-ahead auction. »

All of this would create in essence as many as five different market decision points, compared to the typical tally of two (day-ahead and real-time) as envisoned by FERC's SMD model:

(1) day-ahead (DA),
(2) the post-DA RUC,
(3) hour-ahead (HA),
(4) the post-HA RUC, and finally
(5) real-time.

Power plants might also receive one or more of several types of payments, some mutually exclusive, some not:

- energy price for CAISO dispatch,
- energy price for out-of-market bilateral export,
- availability payment for RUC,
- a payment for providing ancillary services,
- SU/NL payments, or even
- a payment under a future CPUC plan for sale of capacity to a utility that wants to reserve a resource under the CPUC's resource adequacy requirements (RAR), as announced in the January order.

CAISO wants RUC as an extra set of suspenders to make sure that the DA market clears so that power is available to serve load without relying too much on adding schedules in real time. It worries that utility buyers will under-schedule day-ahead. It wants RUC to allow it in effect to give the DA (and HA) market a virtual second go-round. And if a plant doesn't clear at DA, is chosen for RUC, but then later is dispatched for energy, CAISO had long felt that it should rescind the RUC availability payment, to avoid paying a windfall.

Given past history in California, most observers felt that CAISO likely would reserve too much power through the RUC plan. The cost of such excess RUC reservations would end up "socialized" and paid for by state ratepayers. (By contrast, load-serving entities are liable themselves if they under-schedule their own load.)

Power producers, by contrast, saw RUC as a "stealth" call option. If CAISO were allowed to go forward with its plan to rescind the availability payment, generators argued that the call option would go unpaid, especially if the unit's DA bid would serve as the strike price, as proposed initially by CAISO. Plant owners wanted the freedom to submit a new, higher RUC bid to serve as the new strike price, to gain compensation for the option, or else to strike at the market-clearing DA price, the solution that FERC eventually suggested and CAISO accepted.

Dynegy, meanwhile, likens RUC to a stealth put option. Dynegy has said that because CAISO will likely reserve excess resources through the RUC process, it will be left often in real time with the problem of standing down plants that were scheduled to run. In other words, it will be forced to issue decremental dispatch instructions, even if the resource has not submitted a DEC bid. Thus, as a buyer in real time, CAISO in effect acquires a free put option: an option to sell the product back to the seller. And in that case, says Dynegy, the unwinding of the position would require liquidation of the plant owner's position in the same-day gas market, with penalties for imbalances related to transportation gas storage.

Other problems arise, especially regarding the question of whether CAISO could rescind the RUC availability payment on a later dispatch of the unit. Sempra's Don Garber explained how the RUC plan might create "perverse incentives" in the DA market, leading eventually to price inflation in California:

"By offering both a capacity payment and the market-clearing price for energy, RUC may encourage a supplier to withhold its resources from the ISO's day-ahead market by making an offer that is calculated to be too high to clear but still low enough to be selected for RUC."

Southern California Edison agreed with Sempra's warning of market distortions, but Duke and Reliant Energy argued that such fears are groundless, with no evidence that suppliers possess the necessary sophistication to tailor their bids in this way.

In its modifica- (Continued on p. 11)

Many feared that RUC would create "perverse incentives"—suppliers could cash in by bidding too high to clear the energy market, but still low enough to collect a RUC payment.

By late this winter, things had begun to go awry. In a series of public conferences, opponents had attacked the market design as too heavy-handed.

INTERVIEW

Exelon's Rowe Speaks Out

By Lori A. Burkhart


John Rowe

John Rowe, chairman and CEO of Exelon, has been a utility CEO longer than any other currently serving in the energy industry. Previously, he served as chairman, president and CEO of Unicom Corp., preceded by almost ten years as president and CEO of New England Electric System, and prior to that was president and CEO of Central Maine Power Co. from 1984 to 1989. Exelon was created in October 2000 via the merger of two medium-sized utility companies, PECO Energy, based in Philadelphia, and Unicom, the parent company of Commonwealth Edison, based in Chicago. The newly created company survived the chaos of deregulation and marketing and managed to thrive. Exelon now is among the energy companies with the highest market value—about $22 billion—and has become a Fortune 500 company. Exelon serves approximately 5 million electric and gas customers.

Exelon Nuclear operates the largest nuclear fleet in the country. Its Midwest Regional Operating Group oversees six nuclear generating stations housing eleven operating nuclear reactors: Braidwood, Byron, Clinton, Dresden, LaSalle, and Quad Cities. The Group also oversees the decommissioning of Dresden Unit 1 and both units of Zion Station. Exelon's Mid-Atlantic Regional Operating Group oversees four nuclear generating stations housing six operating nuclear reactors: Limerick, Peach Bottom, Three Mile Island Unit 1 and Oyster Creek. The Group also oversees the decommissioning of Peach Bottom Unit 1.

Exelon lately has been in the news because of its stymied efforts to acquire Illinois Power from Texas-based Dynegy, as well as its financial success and two-for-one stock split. Rowe spoke to *Spark* about what it takes to succeed in the now-tumultuous utility industry.

SPARK: At the end January, Exelon increased its dividend by ten percent to $.55 cents per share and announced a two-for-one stock split. To what do you attribute the company's success?

John Rowe: First, to the merger of Unicom and PECO and the opportunity for productivity improvements that it gave. Second, to the wonderful performance of our nuclear fleet the last few years under Oliver Kingsley. Third, to what we call ExelonWay, which is our across-the-board quality and performance improvement program, and fourth, to having had the hardheaded financial discipline to walk away from investments when they don't work. Like everybody we had a betting average, but we bet less on our failures than some, and we have cut our failures off earlier than others have. So I think those four things, all of which exhibit what I would call an absolute and consistent commitment to increasing value have made us successful to date. As you know one always earns it again tomorrow.

SPARK: Last November Exelon announced the acquisition of Illinois Power to form Dynegy, but the deal fell apart due to the failure by the Illinois Legislature to approve a bill on rates and long-term purchased power agreements. How does this change affect Exelon?

JR: We were interested in acquiring Illinois Power, but only if we had a stable rate structure established in Illinois beyond 2006, and the action of the Legislature had just made it clear that we have to go back and work out systems in Illinois that may look more like New Jersey or more like Maryland. We have to find a sound regime for pricing the service to customers who don't shop after the end of the rate freeze period in 2006, and that involves state issues of how the state wants power to be procured for customers who stay with what we call the bundled rate. It involves FERC issues of affiliate transactions and frankly it is just one more example of the issue that has been around the whole twenty years of my career, which is how are distribution utilities to acquire energy in a regime that is partly competitive and partly regulated?

SPARK: Exelon Nuclear operates the largest nuclear fleet in the nation. Why has Exelon chosen to invest so heavily in nuclear power and is the strategy successful?

JR: It is like the great story about why John F. Kennedy became a war hero, he said it was involuntary—they sunk his boat. In the case of Exelon we inherited this position from both our predecessors. These are decisions that were largely made back in the mid-1970s before the Three-Mile Island accident. At the time it appeared to the people managing the two companies that nuclear plants would be environmentally superior to coal and more » economical to coal. I think they were right on the environmental superiority and I think that will prove a long-term advantage to Exelon. But it was clear that after the Three Mile Island event, nuclear plants became more expensive and that caused both PECO and ComEd to be relatively high-cost companies in the 80s and early 90s, and also in that period cost the shareholders a lot of money. In the last few years the nuclear plants have been good to us, and I think there is a real chance they will be even better in the years ahead. But we gave at the office, so to speak, in the 1980s and 1990s.

In the last few years the nuclear plants have been good to us, and I think there is a real chance they will be even better in the years ahead. — *John Rowe, Exelon*

SPARK: Exelon was created in October 2000 via the merger of PECO and Unicom, forming one of the largest utilities in the U.S. After three and one half years, has Exelon achieved the cost savings predicted when the merger was proposed?

JR: We exceeded those in the first two years and we keep finding additional opportunities. Some of them have to do with the merger and some have to do with just applying continuous improvement principles to the individual business units. But there is no doubt there are significant economies from a well-done merger and we continue to see the benefits of those every quarter.

SPARK: Exelon Energy is an unregulated supplier of energy and provides customers with competitive supplies of energy in more than six states. With the slowdown of retail restructuring, in what direction is this business moving?

JR: First, like other people we have not done very well in that business and therefore we have shrunk it with the slowdown. But I am convinced, and so are my colleagues, that we need to keep a retail presence, that we need a more active wholesale and retail marketing function. Our Power Team does day-to-day and quarter-to-quarter creating of business very well, but we need to couple that with serious efforts on a one-, three- and five-year basis to be a supplier to both large retail and smaller wholesale customers, and I think someday a supplier to the smaller retail customers as well. I am absolutely convinced that in the states that have adopted competition it is largely irreversible for good and sufficient reason, and that over time you will see more and more customers buying their power from competitive suppliers. If we want to have the most cost-effective outlet for our capacity, we have to know how to be such a cost-effective marketer.

SPARK: Many electric and gas utilities have gone out of the telecommunications business; will Exelon stay in the telecom business with PecoAdelphia Communications?

JR: Well we are largely out of it and we would be happy to sell that, but the various Adelphia bankruptcies have made that fairly illiquid at the moment.

SPARK: Based on your over various 20 years of experience as a utility CEO, what do you see the industry looking like in the years ahead?

JR: That is a very good question. I think that is as clear now to me as it was twenty years ago. I think you will see more competition, not less. I think sort of like the ivy going through the brick walls, once you have the plants started they tend to grow and to flourish, but I don't see it happening in any orderly, or tidy, or predictable way. I think FERC will continue probably in some fits and starts—due to regional opposition—its efforts to create good regional transmission organizations. We at Exelon ardently support those efforts. I think that over time there will be some standardization of market design principles but it's very clear in the wake of the opposition to FERC's SMD (standard market design) policies that those will be relatively slow in evolving. I think you will see much more intense regulatory insistence on reliability, and I believe the solution to the issue of utilities obtaining the power they provide to the customers who don't shop will differ greatly from state to state as each state experiments with the advantages of integrated utilities and perceived advantages of disagregation in its own way. At Exelon we believe the customers are better off with as much integration as possible, and what we're trying to explore with our commission is how you make that consistent with vibrant wholesale competition and also the evolution of competitive retail markets for about a third of our load.

SPARK: What would you like our readers to know?

JR: I would like the readers to be thinking about the real implications of both competition and the need for further environmental improvement. I think starting with the latter, that the number of states that have adopted renewable portfolio standards is very significant. In my opinion that is not the best way to deal with environmental issues, but it has immense political momentum. I think the weight of scientific opinion that the carbon and climate change issues require attention is getting larger every year and that climate change » issues will have a larger impact upon our policies. I think that natural gas has been the principal fuel to provide a cleaner mix, and now we are dealing with great price volatility issues in natural gas. The easy times for natural gas seems to be over. So this whole issue of how we become cleaner when the fuel of choice is increasingly volatile in price, and the principle renewable that is really expanding is wind—which is an erratic power source—is very challenging. I would certainly urge utility readers to look at the role environmental issues have played in the past thirty years and assume that role even will be larger going forward.

I also think the environmental issue reacts very strongly with the competitive issues. One of the drivers of different kinds of competition are the developers of things like wind power, and I think competition at the wholesale level is here to stay, I think it has largely benefited consumers although it doesn't work in as simple a fashion as people hoped a decade ago. I think we are going to be constantly feeling our way through how to have some of the benefits of competition and some of the benefits of regulation. Alfred Kahn had a wonderful story that partial deregulation is like moving the vehicles in Britain from the left side of the road to the right and being timid starting with the lorries (trucks). It is just a joke designed to illustrate how complicated it is to have competition working for some purposes and regulation for others. But whether you're down in the South where integration is still relatively strong or in the Northeast where competition is more strong, in almost every region you have some mix of competitive principles and regulatory principles at work—and this is very tough stuff not only in our industry but in telephone and other places—and it is going to keep us sort of changing our ground rules.

Lori A. Burkhart is contributing legal editor at Public Utilities Fortnightly magazine.

FEATURE

Submeters Come of Age

By Vance Hall

Vance Hall

The submeter, though historically used for billing allocation in multi-tenant commercial buildings, is expanding its role in the utility arena. Helping provide automated meter reading of multiple metering points, while still allowing frequent retrieval of that information, is only the beginning. Submetering also facilitates more extensive load research projects to verify the effectiveness of existing marketing programs or justify new ones. Today's submeter proves it can save utility customers money and earn their loyalty.

With the right technology and a relatively small sampling of customers, utilities can easily find the data to support or improve their demand-side management and marketing programs. They're also starting to use submeters to collect energy usage data for presentation on a secured Web server and even use the compiled data from load research projects to generate ideas for new services.

All of this has come about because of technical advancements. The metering industry has eliminated some of the technical roadblocks that once prevented true automation of meter reading, data collection and analysis. At one time, these roadblocks generally presented major problems in establishing an unbiased sample population for conducting energy consumption research.

For example, in past years, research meters were large, unsightly pieces of equipment. When a utility approached a commercial or industrial customer to participate in a load study, many customers were afraid that the size of the meter would make the building aesthetically unpleasing. More importantly, research meter installation generally required an interruption of utility service. For most businesses, volunteering to cut off the power for any period of time to participate in a voluntary utility research project with no immediate payback is simply not an option.

Today's load research programs can be done with greater reliability and at a much lower cost. This is because the newest submeters eliminate both of these major obstacles. Today's submeters are smaller and packed with more capabilities. Plus, a utility or third-party vendor can install the submeters with split-core current sensors around the same conductor connected to the billing meter. In other words, there is no

MeterSmart 5000

The MeterSmart 5000 is a KWH/Demand meter with load profiling capabilities. The MeterSmart 5000 meter kit includes one set of three split-core current sensors for ease of installation. It's a versatile meter that can be upgraded to provide power factor and power quality features. It is compatible with MV-90, CE-MON and other standard data formats and is available with a variety of communications options.

service interruption, making the research process invisible to the end customer.

In short, thanks to some innovative companies and new ideas about submetering, positive results are starting to flow from utilities across the country.

Residential Load Study

In one example, a southern U.S. electric co-operative comprised of more than a dozen non-profit member utilities recently embarked on a comprehensive load research study. The project calls for submetering and analysis of more than 1,200 residential customers' homes. The electric water heater, heat pump and supplemental resistance heat are all being metered.

Once the two-year study is finished, the co-operative will see the demand impact of its market-driven programs that promote the use of electric heat pumps and electric water heaters. The results should help them fine-tune the pricing of electric services while identifying profitable new products, services and niche markets. As with any load research project, the co-operative's program involves several steps.

- Defining project scope;
- Sample design and selection;
- Customer recruitment support;
- Equipment procurement, installation, maintenance;
- Data collection, verification and editing (also known as Meter Data Management);
- Data analysis and reporting; and
- Marketing program recommendations.

Measuring Program Effectiveness

In another example, company officials from a large investor-owned utility in the western United States are using submeters and load research to validate the accuracy of a remotely driven thermostat-control initiative. The purpose of the program is to measure usage data and confirm the magnitude and timing of reductions in consumption during control periods.

In this case, thermostats at a sample group of approximately 150 small businesses can be remotely controlled by the utility for increases or decreases of 2 to 4 degrees Fahrenheit. The goal is to reduce energy consumption during peak usage hours and at the same time provide a noticeable reduction in dollars and cents on the electricity bill, and all of this must be undetectable by customers and employees inside the metered buildings.

To get started, in full turnkey fashion, the utility had a submetering solution vendor install submeters without service interruption and conduct interval data collection, processing, analysis and reporting services. Additionally, the vendor was to make energy usage data available to participating customers via a secured Web site. For this project, submeters and runtime sensors were installed on the HVAC units of all customers participating in the study. Each customer shares a phone line with their installed submeter, and each morning between midnight and 6 a.m., the submeter dials a toll-free number to report its data for the day. Currently at its midway point, research data is projecting a 10-Mw demand reduction per hour for every 5,000 customers.

Pinpointing and Eliminating Inefficiency

In a final example, data collected via submetering and load research was used to solve an electrical mystery. A non-profit customer at a utility in Texas received a surprise on its electric bill – an unexpected $8,000 increase. This was twice the normal bill. To identify the problem, officials at the retreat facility turned to their utility for answers. The utility, a co-operative with limited internal resources, turned to a submetering and load research vendor to investigate and recommend a solution.

During the process, the utility and its vendor pinpointed locations where major inefficiencies were occurring and used their findings to make recommendations. As a result of the submeter installation and research that ensued, the non-profit customer implemented an energy efficiency plan to reduce consumption. For instance, there was no need to use the campus' larger worship hall for certain gatherings when a smaller hall could accommodate them. These types of efficiencies started saving the facility large amounts on the electricity bill over time, including a less-than-four-month return on its investment.

In addition, the utility partnered with its generation and transmission provider and submetering solution vendor to offer Web presentation of energy data. Today officials at the retreat facility can monitor their own energy consumption at any time they please.

The common aspect to all three of these examples is eliminating inconvenience to the utility's customer. The technology driving new submetering and automated meter reading initiatives allows utilities to quickly and cost-effectively solve problems and generate new programs and solutions, thereby creating energy customers for life. ■

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California

(Continued from p. 6)

tion of Feb. 24, CAISO said it would drop its proposal to rescind the RUC availability payment. However, to avoid market distortions, it proposed to lower the ceiling on the availability payment to $100/MWh. Further, it would net the availability payment against the energy price cap of $250, in effect limiting the energy payment for a subsequent dispatch to $150/MWh. In this way, CAISO would avoid Garber's "perverse incentives." But obviously, an RUC program structured in this way becomes almost entirely divorced from the idea of a capacity market, as FERC would prefer.

A payment of $100/MWh has no logical relationship with fixed capacity costs. Instead, what CAISO is doing through RUC is creating an energy market product with a dual-payment structure: a down payment and a settlement payment. What, then, is the purpose of RUC?

According to lawyers for the City of Redding, California (Lisa Gast and James Pembroke), RUC was imagined by some not as a surrogate capacity market, but as a hedge for certain power generators with longer start-up lead times. Without RUC, the argument went, such units would suffer a disadvantage in the HA and RT markets, if they failed to clear day-ahead. But Gast and Pembroke show how that idea was exposed when it became known that such resources, identified as essential to meet native load, had in fact found a way to make themselves available in the HA market for export.

Williams Power and Dynegy also argue that a receipt of a RUC payment should not serve to restrict a seller's opportunity to sell the energy behind the capacity, such as through a bilateral export. Dynegy offers a constructive example.

Suppose a plant owner bids $50/MWh in CAISO's DA market in the winter season (off-peak for California, on-peak for the Pacific Northwest). The bid fails to clear, but CAISO commits the plant for RUC. Then suppose a cold snap occurs up North, and the owner schedules the output as an export out of CAISO in the HA scheduling process at a bilateral price of $250.

Now, if CAISO recalled the power at $50, buyers outside CAISO would view California as "hoarding" resources at a time of need in neighboring control areas. And, as Dynegy explains, plant owners in California would choose to sell energy bilaterally whenever possible to avoid the risk of losing money to a stealth call option struck by CAISO at below market.

These examples lead many to complain that RUC, if accepted, should be redesigned as a capacity-only product, FERC has advised. They warned that RUC would function as an energy »

Tell Us About It

Fortnightly's Spark is interested in hearing from you. We want to know what you think about prevailing issues that may or may not be mentioned in this issue. Be advised ***Spark*** may publish your thoughts. To get things started, ***Spark*** notes that our April ***Fortnightly*** examines the role of LNG in the natural gas market. ***Spark*** wants to know if you think LNG can save the day?

Send your responses to *radford@pur.com* product. That, they say, would compromise any sense of independence by allowing CAISO to take a position in the energy market, to the apparent benefit of retail consumers. Dynegy adds that an RUC energy product will also distort markets by reducing risk for utilities and load-serving entities (LSEs) who buy power in CAISO markets to serve load:

"Allowing CAISO to hold energy positions will stress CAISO's credit capacity and increase CAISO's exposure to claims of imprudence.

"LSEs will have an incentive to underbid because they can lower the DA energy market clearing price and know that their net short energy and capacity needs will get filled by CAISO on a least-cost basis.

"In other words, LSEs will have two bites at the apple: one in the DA energy market and another through RUC."

Redundant Reliability?

Now enter the CPUC, with its interim opinion on utility resource plans and cost recovery mechanisms for generation procurement. In that order, the CPUC announced two new policies especially relevant to the CAISO market design, and the RUC process. (*See, CPUC Decision No. 04-01-050, R. 01-10-024, Jan. 22, 2004.*)

First, the CPUC ordered the state's three major investor-owned electric utilities, by year 2007, to employ forward contracts of at least one year's duration to procure at least 90 percent of the power supplies they will need to meet demand during the summer peaking season, May through September.

Second, the CPUC established a framework for a resource adequacy requirement (RAR), a concept that it introduced in its SMD white paper, as a reliability policy to fall under state jurisdiction. The RAR would function as a state-mandated reserve requirement.

The CPUC's RAR framework would subdivide the reserve requirement into two pieces. A short-term operation reserve margin (ORM), taking outages into account, was pegged at seven percent. The addition of a second, longer-term margin, the planning reserve margin (PRM), calculated without adjustment for outages, and when added on top of the ORM, would bring the total the total reserve margin up to a range of 15-17 percent.

Note, however, that the CPUC deferred the reserve margin requirements, just as it did the summer forward contracting rule. Thus, in 2004, utilities need only comply with the seven-percent ORM test, but then must add at least a two-percent margin increment to their reserve each year, from 2005 through 2008.

Many stakeholders argue that given the CPUC's RAR plan, that CAISO's FOO/RUC regime is redundant. Each is designed for the same purpose: to ensure an adequate supply of power.

Williams believes that the CPUC is dragging its feet on the RAR plan and because the CAISO's proposals, by covering the same ground, give it an out to go slow:

"Instead of providing appropriate incentives … the must-offer obligation appears to be having the exact opposite effect, thus incenting the CPUC to phase-in resource adequacy over several years."

Also, as Williams notes, the CPUC in its order has conceded at attempt to delay:

"[T]here is almost 3000 MW of capacity that is curently required to be offered to the marketplace through 2006 as part of a settlement regarding market manipulation.

"Setting a reserve requirement either too high or reaching it too quickly could result in California utilities potentially having to pay excess amounts to acquire these resources that otherwise would be offered at cost."

In other words, even regulators sometimes are guilty of "leaning on the system." ■

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