Energy Choice Matters

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Axe Falls for 80 at Commerce Energy

Struggling retailer Commerce Energy dismissed 80 employees, or about 31% of its workforce, and will exit its energy consulting business, Skipping Stone.

Commerce has been plagued by higher acquisition, personnel, and bad debt costs while losing customers, leading to a $1.2 million loss in the most recently reported quarter (Matters, 3/13/08).

Commerce called many of the cut jobs duplicative, and is closing its offices in Houston and Boston, used mainly by Skipping Stone, and is also significantly downsizing its Irving, Texas office. The workforce reduction is expected to generate more than $5 million in annualized pre-tax cost savings.

CEO Gregory Craig reported the job cuts were part of a broader restructuring and streamlining that includes centralizing all core functions at its headquarters in Orange County, Calif.

SPP Imbalance Market Success Should Lead to New Markets, Consultant Says

The success of the Southwest Power Pool's Energy Imbalance Service (EIS) Market should give the SPP Board and members the confidence to accelerate efforts toward creating new markets, Boston Pacific urged in a report filed at FERC (ZZ08-4) on the EIS Market's first 11 months.

The benefits envisioned by stakeholders have been realized, Boston Pacific added. Boston Pacific calculated trade benefits (production cost savings) of over $100 million as a result of dispatching more efficient, lower-priced units.

The imbalance market is also resolving the majority of the congestion in the EIS Market footprint, the consultant added, accomplished mostly by increasing generation on the constrained side of a flowgate and decreasing generation on the unconstrained side of a flowgate. Such market action is less costly than pro rata curtailment, Boston Pacific noted. Prices are also now transparently calculated and reported in a spot market, providing liquidity for new generation investment by IPPs and developers responding to state competitive procurements.

SPP has started preliminary efforts to potentially develop two additional markets: an Ancillary Services Market and a Day-Ahead Energy Market, and recently hired Ventex to conduct a cost-benefit study for those markets.

"Given the success of the EIS Market, we recommend that, if at all possible, SPP accelerate the effort to open new markets in order to realize the potential benefits of central commitment and ancillary services markets," Boston Pacific urged.

Boston Pacific recommended a continuing effort to attract more and different competitors, including pure financial investors as well as generation developers responding to state competitive procurements, into the imbalance market. The number and quality of competitors is what drives the benefits of any competitive market, Boston Pacific reasoned.

To further attract new competitors, SPP should develop a hub where futures contracts are traded, Boston Pacific proposed. That could help attract diverse participants such as financial houses to participate in the market.

By a variety of measures, Boston Pacific reported a competitive imbalance market.

Boston Pacific took "comfort" in the fact that prices in the first eleven months of EIS Market operation have consistently been in-line with prices in Midwest ISO and ERCOT, though the consultant noted the prices aren't expected to be identical due to different maturation levels, resource mixes and patterns of demand.

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Power Marketers Warn Against GHG Allowance Allocation to Incumbent LSEs

Allocating greenhouse gas emission allowances to load serving entities, particularly only to incumbent IOUs, would give utilities an unfair advantage, power marketers told the California PUC (R. 06-04-009).

Dynegy "unequivocally opposes" a system that proposes no cost or other preferential allocations to LSEs while IPPs would be required to purchase allocations from LSEs or other marketers.

Such an LSE preferential allocation scheme is clearly discriminatory, given California's hybrid procurement system where LSEs also own generating resources, Dynegy pointed out.

The Western Power Trading Forum explained that incumbent IOUs would have an "inherent conflict of interest" as the recipient of the allowances because in most instances, they also own generating resources and/or are in direct competition with non-jurisdictional entities for providing electricity to retail load. Thus, a direct allocation of allowances to jurisdictional retail providers would potentially confer an unfair competitive advantage to utility-owned resources in procuring allowances, and create a concentration of market power, WPTF claimed.

LSEs, Dynegy noted, are likely to have more options for achieving carbon reductions than generators, since LSEs can pursue demand reduction and efficiency programs for their end use customers, or can shift power purchases to less carbon intensive producers. Generators' only option for reducing carbon production, however, is to generate less, since there are currently no proven technologies for removing carbon from fossil fuel emissions, Dynegy reminded.

Recovery of the allowance costs by IPPs will be subject to market conditions and risk, whereas recovery of the same costs by regulated utility generators may be assured via cost-of-service based ratemaking, Dynegy added.

Thus, existing sources should receive some, if not all, of their allocations based on historic emissions performance, since that historic performance has been, by definition, in compliance with all then-existing regulatory requirements, urged Dynegy.

Such an allocation system will, in part, recognize the reliability benefits conferred by such sources, provide funding for emission reductions investments, and offset some of the loss of market value of these resources, Dynegy reasoned.

Zero carbon generators should not be included in the allocation of emission allowances, Dynegy argued, because such generation is already promoted through RPS and other programs, and such generation will benefit from marginal units' premiums to cover carbon costs while not having to pay any costs themselves.

However, Southern California Edison contended emission allocations should go to those entities suffering the most economic harm, such as LSEs and their end users, and cautioned against providing windfall profits by allocating them to generators

Should California decide to auction allowances, Dynegy recommended that the state prevent auction participants from creating artificial scarcity by buying and retiring allowances.

Initially, participation in the auction should be limited to entities in the regulated sectors to prevent speculators from profiting by trying to gain market power in tradable allowances, Dynegy suggested.

But Morgan Stanley Capital Group strongly opposed limiting participation in the allowance market to only those entities with compliance obligations.

Exclusion of entities such as financial institutions, hedge funds, or private citizens would be difficult, if not impossible, to enforce, Morgan Stanley observed, and would have negative consequences for the offset market.

Attempts to prevent entities without compliance obligations from participating are unlikely to succeed, Morgan Stanley reported, since such excluded entities could simply contract with an eligible participant to undertake trades at the direction of that excluded entity.

Meanwhile, maximizing the number and type of market participants would bring significant benefits such as greater liquidity and price stability, Morgan Stanley argued.

Illiquid markets exacerbate price volatility, are easier to manipulate, and can force a party urgently needing to transact to buy or sell at an out-of-market price, Morgan Stanley noted.

WPTF cautioned against relying on a higher RPS target (such as 33%) to meet AB 32's goals because it presumes that renewable resource development is more cost effective than other emission reduction opportunities that are achievable elsewhere or through different technologies. A multi-sector trading system ensures the most cost-effective GHG reductions are pursued, WPTF explained.

WPTF also argued that for maximum efficiency in reducing GHG emissions, electricity consumers must be fully aware of the carbon costs that their electricity consumption creates. The Independent Energy Producers Association agreed, noting that customer behavioral changes will ultimately be needed to achieve the state's reduction goals in the quickest, most cost-effective manner. But such changes may be stymied by insulating retail customers from wholesale costs of GHG compliance.

Thus, any mechanism that returns auction revenue to consumers should do so in a way that does not discourage consumer energy efficiency. Year-end rebates of auction revenues would be an acceptable auction revenue return mechanism, WPTF noted, whereas an application of auction revenues to directly reduce electricity rates would not.

While not its first preference, TURN can support a capped system if all allowances are auctioned and the proceeds are used to benefit lower-income customers and to offset the costs of emission reductions in the electric sector.

TURN argued there is "no need" for secondary market trading of emission allowances, as long as allowance prices are capped at a reasonable level and the revenues from allowance sales are used within the electric sector.

The environmental goals of AB 32 can be achieved more equitably with a "cap and auction" program that does not include a "trade" component, TURN asserted.

TURN suggested any market trading mechanism is subject to potential abuse by speculators and is unaware of any PUC proposals that would address the potential for speculation or market power exercised by entities that purchase allowances without any compliance obligation.

Briefly:

Delmarva Signs 100 MW of Wind Power

Delmarva Power signed for its Delaware customers two 20-year PPAs for 100 MW of land-based wind power from Synergics Wind Energy, which intends to build the wind farms in Maryland. Delmarva reported the contract price is "much lower" than that in the controversial Bluewater Wind offshore proposal. One PPA would be for up to 40 MW starting in 2009 and the other would be for up to 60 MW starting in 2010, pending Delaware PSC approval. Delmarva is still negotiating with other wind developers selected in May for about 360 MW (Matters, 5/8/08).

ALJ Favors Dismissing PUB Complaint Against TriEagle, Starlight

A proposal for decision would dismiss Public Utilities Brokers' complaint against TriEagle Energy and Starlight Electric in docket 32405 since TriEagle has settled with all individual customers and has paid any remittances required under the pacts (Matters, 5/1/08). TriEagle had moved that since there were no outstanding issues, the docket should be dismissed. An ALJ agreed, concluding PUB has not asserted a claim for which redress is available in the docket. The ALJ refused to rule on whether PUB had standing to pursue any claim since the settlements have made the question moot, and to rule on the question would amount to a discouraged advisory opinion.

REPs Question Fate of AMIN Meters When Customers Switch Providers

The treatment of advanced meters installed under CenterPoint Energy's advanced metering information network (AMIN) program (35620) when customers switch REPs is a main concern of retailers, as revealed in separate RFIs issued by the Alliance for Retail Markets and TXU Energy. Under the AMIN plan (Matters, 5/26/08), REPs could voluntarily fund advanced meter installations ahead of CenterPoint's deployment plan in docket 35639. ARM asked whether the smart meter remains installed at a customer's location if that customer switches providers, or whether the REP paying for the meter can have it moved (and what timeline and costs would be involved). Similarly, TXU Energy asked if a customer's old REP paid for a smart meter and choose not to remove it, could the customer's new REP have access to the meter. ARM also asked whether CenterPoint considered the possible impact of REP-driven meter deployment on ERCOT load profiles and ERCOT settlement, or unaccounted for energy (UFE) in ERCOT.

Ambridge Amendment Concerning Sale, Customer Transfer Approved by PUCT

The PUCT approved an amendment to Ambridge Energy's REP certificate which recognizes that it has been purchased by Champion Energy Holdings (Matters, 5/8/08). As part of a series of transactions, Ambridge's existing customers and wholesale positions are to be transferred to Champion Energy Services, now principally owned by Ambridge's owner James Crane, while Ambridge retains its REP certificate and intends to acquire new customers in the near future (35654). Ambridge, a Houston-based start-up which completed ERCOT testing about a year ago, recently amended its REP certificate to add the trade name Guaranteed Electric, under which it markets prepaid service (Matters, 4/1/08).

Hess Gas License Extended in Ohio Pending Renewal

Hess received an extension for the expiration its current Ohio gas license until June 29 to avoid potential adverse consequences to affected customers as PUCO considers Hess's late-filed renewal application (04-683-GA-CRS). Hess's license was due to expire June 8, but the extension prevents any service interruptions as PUCO considers Hess's renewal filed May 29. Suppliers are required to file renewals at least 30 days prior to the expiration date.

SPP Market ... from 1

Specifically, the simple average price in the EIS Market was $49.18/MWh which is 7.2% below ERCOT's price and 3.8% above MISO's price. EIS Market prices are also in-line with ERCOT and MISO prices on a monthly and hourly basis.

Weighted average hourly prices at the EIS Market's 10 load settlement locations are within 15% of the SPP-wide weighted average hourly price of $51.78/MWh. Southwestern Public Service had the highest at $59.09/MWh while Grand River Dam Authority had the lowest ($46.38/MWh).

When examining prices at every price location - not just aggregated to load settlement locations - for each five-minute dispatch interval, Boston Pacific determined that that 97.1% of these locational prices, by interval, fell between zero to $100/MWh, which Boston Pacific termed an "expected range."

The EIS Market's coefficient of variation (48%), which measures volatility, was much lower than that of MISO (69%) and ERCOT (89%). The maximum SPP-wide hourly price was not even $400/MWh, while in MISO the maximum price was over $600/MWh and in ERCOT was $1,500/MWh.

Participation in the EIS Market was "robust," Boston Pacific concluded, with 81% of capacity made available for dispatch on average. EIS Market sales of 13.2 million MWh were roughly 8% of total load within the EIS Market footprint.

However, the average portion of available capacity made available for dispatch (the average dispatchable range) was 47%. Although that is a "reasonable" range on an overall basis, Boston Pacific noted the Market Monitoring Unit (MMU) has raised some concerns that individual Market Participants are not submitting reasonable dispatchable ranges. Some participants have even given the same value for their minimum operating limit as their maximum operating limit. The MMU sent a letter in March notifying Market Participants that all resource plan information must represent true operating constraints.

The MMU also has concerns about ramp rates and is working with Market Participants to increase the offered ramp rates to ensure more responsive dispatch.

Prices almost never cleared at the SPP Offer Cap, as such offers were accepted a "negligible" 0.02% of the resource intervals. Offers cleared within 5% of the FERC offer cap about the same amount of time.

Boston Pacific considered the EIS Market's 21 Market Participants a "good number" of competitors.

No Market Participant had a market share at or above 20% for the first 11 months of the EIS

Market, which is the FERC threshold for a rebuttable presumption that a supplier cannot exercise market power when considering market based rates.

The market's Herfindahl-Hirschman Index was 1,103 as measured by winning market shares of sales in the EIS Market, just above the "safe harbor" level set by FERC. HHI is 1,414 when measured by the shares of capacity made available to the EIS Market at the peak hour of the 11-month period, which is in the middle of the moderate concentration zone of 1,000 to 1,800.

The EIS Market's 11 months of operation in 2007 would not have yielded sufficient revenue to warrant investment in new generation, Boston Pacific reported. Market revenues were insufficient to cover the fixed costs of either a gas-fired peaking turbine or intermediate combined cycle unit. The combined cycle plant would have been run in about 52% of all hours with net revenue covering about 65% of the first-year fixed costs. The combustion turbine power plant would have run about 6% of all hours with net revenue covering about 17% of first-year fixed costs.

The results are not surprising given SPP's 33% resource margin, Boston Pacific observed.

Transmission congestion is "pervasive" in the EIS Market, Boston Pacific reported. The number of days of transmission outages increased 30% from 8,581 days in 2006 to 11,149 days in 2007.

At least one flowgate experienced congestion in each five-minute dispatch interval 56% of the time over the 11-month period. However, 75% of the congestion occurred on just 10 flowgates (out of a total number of over 200 flowgates).

The EIS Market was able to resolve 85% of congestion through redispatch of units, a tool unavailable before the market started.

Although a major reason for higher congestion likely was two major ice storms in 2007, the significant increase in outages should be studied by SPP and the MMU, Boston Pacific suggested, to alleviate any concerns of market power abuse through forced or maintenance outages. The reasons for transmission outages should be routinely recorded and published, the consultant added.

SPP should also revisit the coordination between the physical congestion management done by the Market Operating System (MOS) and the financial allocation of costs done with the Curtailment/Adjustment Tool (CAT).

To expand support for transmission investment, Boston Pacific recommended highlighting the strategic or policy goals served by that investment, such as integrating new wind power or relieving congestion.

The success of wind power in the SPP area should be both "celebrated and managed," Boston Pacific advised.

The consultant favors standardizing the measure of capacity contribution from wind. In data that Boston Pacific received, it appears some members assign 0 MW to summer capability for wind, while others assign the nameplate capacity of the wind turbine as its summer capability. Some standard should be used to help effectively forecast capacity contribution, Boston Pacific recommended. Although SPP Criteria 12.1.5.3(g) appears to address this concern, Boston Pacific did not observe the rule being applied in the data.

Boston Pacific also suggested that SPP explore certification of RECs as PJM and MISO do to give RECs credibility.

Coal-fired power accounted for 64% of the electricity output in the market during the eleven-month period, while gas/oil accounted for 26% and nuclear 6%. Renewables made up over 3% of the EIS Market.

Gas/oil was at the margin 82% of the time, and coal was at the margin about 17% of the time.

Boston Pacific attributed the success of the EIS Market to the collaborative process between the SPP board, Regional State Committee, FERC and other stakeholders that created and tested the market. SPP was able to correct problems encountered before the market started through trials, preventing any fundamental problems since the market's start.