Energy Choice Matters

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SPP Says Integration of Entergy Texas Produces Net Benefits Under Most Scenarios

Integration of Entergy Texas with SPP is a "better choice" than integration with ERCOT, based on a cost-benefit analysis of integration as well as a comparison between average on-peak wholesale prices between the two RTOs, SPP told the PUCT in a report (33687). The PUCT is examining both integrations as part of a potential transition to competition for Entergy.

SPP studied six possible integration scenarios, comprising different possibilities for gas prices ($7 vs $11/MMBtu), the location of the Cottonwood plant (ERCOT versus the Eastern Interconnect), and whether the Weber-Richard 500 kV line is built.

Under five of the scenarios, SPP reported net benefits, from $36 million to $201.5 million, from integration.

The only scenario to see net costs was the scenario where Cottonwood would remain in the Eastern Interconnect, gas is estimated at $7, and the Weber-Richard 500 kV line is built, which would produce a net cost of $105.9 million. The line may be needed to assure sufficient Available Transmission Capability (ATC) into Entergy Texas is available to alleviate any market power concerns.

However, based upon current cost allocation methodologies within SPP for economic transmission projects, some of the project costs could be borne by parties other than Entergy Texas, which could result in increased net benefits to Entergy even under the Weber-Richard scenario described above. If 46% or more of the $229 million cost of the Weber-Richard line were allocated to parties other than Entergy Texas, the case would produce net positive benefits to Entergy Texas, SPP said.

... Continued Page 5

PUCO OKs Duke ESP Pact; Allows Residential Gov't Aggregation to Avoid Some Capacity Charges

Residential customers of governmental aggregations would be able to bypass some capacity charges of Duke Energy's Electric Security Plan (ESP), but would not receive a 6% shopping credit available to non-residential customers, under a PUCO order approving a stipulation that implements the ESP (Matters, 10/29/08).

Under the stipulation, all customers may bypass the following generation charges, which make up the price to compare:

- Base Generation (PTC-BG, aka Little "g")
- Fuel, Purchased Power and Emission Allowances (PTC-FPP)
- Annually Adjusted Component (PTC-AAC)

Generally, nonbypassable generation charges include:

- System Resource Adequacy (SRA)
  - Capacity Dedication (SRA-CD)
  - Market Capacity Purchases (SRA-SRT)
- Regulatory Transition Charge (RTC)

However, the stipulation holds that non-residential shopping customers, and non-residential government aggregations, may bypass Market Capacity Purchases (SRA-SRT), provided that such customers agree to remain off the Standard Service Offer (SSO) through December 31, 2011 and agree to pay 115% of the SSO price if they do return. Such non-residential customers will also receive a generation price shopping credit equal to 6% of the current Little "g" price, which is equal to Rider

... Continued Page 6

Maine PUC Draft Recommends Reforms to ISO-NE, Pursuing Hybrid Structure if Reforms Fail

Maine would pursue additional development of a scenario that would see its transmission owners (TOs) leave ISO New England and only participate in a limited amount of ISO functions if Central Maine Power and Bangor Hydro-Electric are unable to win reforms to ISO-NE transmission cost allocation policy and governing agreements, a recommended Maine PUC decision would hold (2008-156).

The recommended decision would find that, "the present arrangement with ISO-NE is, at best, undesirable." However, the hearing examiners determined that pursuing reforms of the ISO-NE market is the best alternative.

But if those reforms cannot be won, the PUC would investigate having TOs leave the ISO as full members, and pursue "a la carte" participation in various ISO markets and functions.

Among the chief areas where ISO-NE is deficient is in transmission cost allocation, the hearing examiners found. TOs would be directed to pursue changes at the ISO to introduce a beneficiaries-pay model, rather than a socialized model, for transmission projects. Some lawmakers and stakeholders believe socialized cost allocation penalizes Maine customers.

The current socialized cost allocation does not provide appropriate price signals and incentives to prospective users of the transmission system, the draft says, and encourages generators to make less than optimal siting decisions.

Furthermore, cost socialization can encourage overbuilding of transmission capacity to obtain the benefits of such socialization -- meaning TOs build more projects so that they pay less through the regional transmission rate for other projects than they receive in payment for their own Pooled Transmission Facility investments.

Additionally, the TOs' compelling profit incentive from transmission returns on equity, plus FERC transmission incentives, combined with ISO-NE's focus on reliability (but not cost-containment), results in a focus on transmission investment over other possible approaches such as demand response or locating generation closer to load, the hearing examiners said.

"The lack of consumer or cost orientation by the ISO coupled with the flawed transmission cost allocation and cost containment mechanisms discussed above are detrimental to Maine ratepayers and have resulted in substantial costs to Maine consumers," the draft found.

The draft recommends changing ISO-NE's mandate, focus and culture by incorporating language in the governing documents of ISO-NE to explicitly include costs as a factor to be considered in decisions about reliability

Regional planning procedures must be modified, the hearing examiners said. ISO-NE's open season approach to soliciting transmission alternatives must ensure that all reasonable alternatives to a transmission project are credibly presented and fully considered, the draft recommended.

While the recommended decision believes it would be ideal for Maine to continue participation in the Forward Capacity Market, doing so would only be beneficial if states win, through the appeals courts, the authority to set the installed capacity level, which is currently set by FERC. States should define, in accordance with NERC, what types of capacity LSEs must provide in order to meet their obligations, the hearing examiners said.

Under the recommended decision, BHE and CMP would pursue the above reforms in concert with renewal of their Transmission Operating Agreements (which expire in February 2010). TOs would report to the Commission on March 31, 2009, and again on June 15, 2009, on their progress. The Operating Agreements require any withdrawal to be noticed by August 1, 2009.

After receiving the March 31, 2009 report, the Commission would consider what actions, if any, the utilities should take with regard to planning for and developing an alternative hybrid model to the reform option. After receiving the June 15, 2009 report, the Commission, after providing an opportunity for comment, would make a determination as to whether CMP and BHE should exercise their rights to non-renewal of the Transmission Operating Agreement.

The recommended decision finds the "hybrid" model to be the next best alternative to ISO-NE membership. Essentially, TOs would pick and choose which functions of ISO-NE they would participate in, a la carte.

The draft finds that the best hybrid option for Maine would include the following features: (1) remaining within the ISO New England control area (or balancing authority area), in terms of the reliability and operational aspects of the system; (2) continued participation in the ISO-NE markets (including capacity); (3) transmission cost allocation that moves from 100% socialization toward "hybrid/beneficiary pays"; (4) disciplined and cost-conscious decision-making about investments, particularly transmission; (5) consumer representation in governance.

As part of the ISO-NE control area under the hybrid option, Maine would remain within a bulk power system in which reliability objectives could be met more effectively and efficiently than by a smaller system, the hearing examiners said.

Although, "[n]either an examination of the record nor of relevant precedent answers the question of the extent of ISO-NE's obligation to provide services to utilities outside of its RTO," the hearing examiners conclude it is likely ISO-NE will provide control area service to Maine on a voluntary basis, and the question is rather a matter of cost -- whether service will be cost-based or include a premium. Under this rationale, the recommended decision dismisses arguments from generators that the hybrid approach would substantially raise costs because Maine would have to provide its own reserves, instead of relying on a larger pool to defray the amount of reserves needed.

The recommended decision found that a stand-alone state Independent Transmission Company, which would also include a state-regulated LSE and utility ratebased generation, is the least promising alternative, due to the sheer costs, risks from ratebased generation and stranded costs, and the elimination of retail competition.

Moving the entire state into the Maritimes control area was also not recommended, as it would be less liquid than ISO New England, and would require market mitigation which may not be workable.

Constellation-EDF Enter Definitive $4.5 Billion Nuclear Agreement

In what was hardly a surprise given the size of EDF's offer, Constellation Energy and EDF Development entered a definitive investment agreement which will see EDF acquire 49.99% of Constellation's nuclear generation and operation business for $4.5 billion.

Constellation and MidAmerican Energy Holdings, which had offered only $4.7 billion for all of Constellation, said they had jointly agreed to terminate the transaction. MidAmerican will receive $2.1 billion in compensation as part of the termination, including $593 million in cash and retaining a 9.9% Constellation stake valued at $530 million. Constellation will give MidAmerican a $1 billion note earning 14% a year that matures at the end of 2009.

The EDF agreement includes $1 billion in immediate cash, and an option to sell to EDF up to $2 billion of non-nuclear generation assets. EDF has provided Constellation a $600 million interim backstop liquidity facility, which will remain available until receipt of all regulatory approvals relating to the transfer of the non-nuclear generation assets that could be sold under the asset put option, or the date that is six months after the date of the investment agreement, whichever is earlier.

Constellation will remain an independent publicly traded company, which it said would provide an opportunity for shareholders to achieve greater value for the company's significant asset base.

EDF Development Inc.'s interest in Constellation's 3,869 MW nuclear group will be structured as a new joint venture between the companies, separate from the existing UniStar joint venture.

EDF and Constellation anticipate receiving necessary regulatory approvals within nine months, and said Maryland PSC approval was not required.

Briefly:

Calif. PUC Solicits Comments on Reviewing Novated Contracts

Stakeholders were invited by the California PUC to submit comments on considerations that should apply in determining whether any replacement contracts used to remove the Department of Water Resources from its power supply role are just and reasonable (R. 07-05-025). Comments should also address the appropriate process for providing adequate notice to - and receiving input from - interested parties regarding novation who are not represented in a working group which will negotiate contract novations. The working group will consist of representatives from DWR, the IOUs, and Commission Staff. The PUC also solicited comments on to how to allocate any early release of DWR reserves to ratepayers, and on developing a procedural schedule for addressing Phase II (b) issues in the PUC's review of reinstating direct access.

ALJ Recommends ICC Provide Interlocutory Review of ABC Complaint Ruling, Affirm Decision

The Illinois Commerce Commission should provide interlocutory review of an ALJ's ruling denying dismissal of the complaint of BlueStar Energy Services against three brokers under the new ABC law, as a definitive affirmation of the ruling will clarify the requisites for initiating a complaint under Section 10-108 of the Act and Section 200.170 of the Commission's Rules, the ALJ said (Matters, 12/2/08). The ALJ recommended that the Commission affirm BlueStar's standing, and that the Commission not consider arguments raised for the first time in the motion for interlocutory review (such as the argument the complaint is premature because the only remedy available under law is license revocation, which cannot occur as no licensing process has been adopted yet). In the complaint, BlueStar alleged American Energy Solutions, Affiliate Power Purchasers International, and Lower Electric failed to disclose anticipated remuneration to customers, as required by the ABC law.

PUCO Clarifies Retail Gas Contract Order, Limit on Termination Fees

PUCO clarified yesterday that its September order relating to gas marketing and contracting rules was intended to adopt Staff's proposal to prohibit suppliers from imposing termination fees on variable products that do not set prices via an understandable formula based on publicly available indices or data. Variable offers that only disclose pricing by describing the factors that will cause price changes cannot impose a termination fee. As noted in our September story (Matters, 9/25/08 at p. 6), PUCO's order clearly stated its intention to implement the termination fee prohibition, but the attached codes for publication inadvertently omitted language concerning the prohibition.

Final Ohio Utility Service Rules Remove Prohibition on Check Cashing Stores as Payment Vendors

A final rule on revised credit and disconnection rules for Ohio utilities drops draft language which would have prohibited utilities and competitive marketers from accepting payments at payday loan centers and check cashing stores (Matters, 6/26/08). PUCO dropped the language due to legislative reforms, ratified in the November election, which cap the interest rate on payday loans at 28%, finding that such a cap answers Staff's concerns about use of such check cashing outlets to accept utility payments. The final rules also do not apply to electric service (only gas and other utility services) as originally proposed, as PUCO decided to keep rules for electric credit and disconnection in Chapter 4901:1-10 of the Ohio Administrative Code. The Commission also found that it would be premature to develop regulations regarding prepaid meters at this time. PUCO revised the natural gas Percentage of Income Payment Plan (PIPP) assistance program by reducing payments for program-eligible customers from 10% to 6% of their income, in an effort to make natural gas payments more affordable for program participants and to encourage more regular PIPP payments.

Private Equity Firm Seeks Acquisition of MMC Energy

Private equity firm Global Asset Capital has made a proposal to acquire independent power producer and developer MMC Energy for $28 million in cash, a premium of 310% over MMC's closing price on December 16, 2008. In a letter to MMC's board, Global Asset Capital General Partner Riaz Valani criticized MMC's "piecemeal" sales of assets in apparent hopes of avoiding insolvency, which Global Asset Capital sees an ineffective and diminishing shareholder value.

The alternative to Global Asset Capital's proposal, "is for stockholders to witness management burning almost $1 million per month with little to show for it - the Company has failed to sign long-term off-take contracts for energy or to secure permits for its largest power development site, and is facing declining energy demand and a declining market for energy related assets," Valani said.

Peoples Energy Services to Turn in Illinois Marketing Licenses

Peoples Energy Services requested to relinquish its Illinois electric and gas marketing licenses as all of its customers were transferred to affiliate Integrys Energy Services by the first quarter of 2008, and the marketer has no plans to serve customers in the future.

Entergy ... from 1

Additionally, based upon historical average on-peak wholesale electricity prices from October 2007 through October 2008 for SPP and ERCOT, Entergy Texas integration into SPP is the better choice, SPP said. During this period, SPP's average on-peak wholesale price was approximately $39/MWh as compared to ERCOT's average on-peak price of approximately $61/MWh, indicating increased opportunity for retail rate reductions, assuming savings at the wholesale level are passed through to retail.

Reliability project costs for integration are $105 million under all scenarios. Economic transmission costs are $239 million in scenarios requiring the Weber-Richard line and $10 million in scenarios without the line.

A Potomac Economics market power study did not identify any market power issues associated with Entergy Texas integration into SPP in 2012 when the Weber-Richard 500 kV line is included in the analysis, SPP said.

An analysis of the local market power issues in the Entergy Texas area indicated "limited" potential competitive concerns in the area or Western Sub-region. The market concentration results indicate that the market in the Entergy Texas area will support "workable competition," although the concentrations are in the highly-concentrated range. Requiring Entergy Texas to sell a portion of its capacity via capacity auctions as described in PURA and PUCT rules would substantially reduce the market concentration in the area, SPP said.

Most scenarios under a pivotal supplier analysis show that Entergy Texas will not be pivotal (including all analyses of the Western Sub-region). In two cases where Potomac Economics found Entergy Texas to be pivotal, a number of factors significantly eased Potomac's competitive concerns. First, Entergy Texas has a number of Reliability-Must-Run (RMR) obligations in the area that compel its generation to run to support the reliability of the system, which would prevent Entergy from threatening to withhold supply. Second, in the scenarios that show Entergy Texas to be pivotal, it is pivotal over a relatively small portion of the load. Hence, Entergy Texas would have to withhold most of its resources to raise prices to a small portion of load.

Further, the magnitude of that price increase would be limited by Entergy Texas' obligations as a provider-of-last-resort. Although the specifics of the POLR pricing provisions that would be implemented are not yet known, "it is highly unlikely that they would allow a price increase large enough to make withholding profitable in this case," SPP said. Additionally, Entergy Texas would only be pivotal in a small number of hours in the scenarios showing it is pivotal.

Based on the analysis, Potomac Economics found that market power mitigation measures are not necessary to address competitive issues in integration. SPP recommended capacity auctions as contemplated in PURA if policymakers wanted additional assurances against market power, as these would be more cost-effective than additional transmission capacity

The capital cost of implementing system functions to implement retail open access range from $2.3 million to $4.8 million, with on-going maintenance costs estimated to be in the range of $615,000 to $1.2 million. Only capital costs were included in the cost/benefit analysis.

ERCOT would continue to manage the customer registration process in the same manner it does today under Entergy Texas' SPP integration, which includes loading ESI IDs for the Entergy Texas area into the registration database, assisting with retail market testing, qualifying TDSPs and REPs for retail transactions, managing the dispute process for data in the retail customer registration system, and validating meter data.

SPP would use its existing processes and procedures to register each REP (including Entergy Texas' affiliated REP) as a Transmission Customer (TC) within SPP. As participants in the SPP region, REPs would be considered TCs. Each TC with load must request transmission service from SPP, designating resources to serve its load. SPP studies each transmission service request and either approves the request or identifies transmission upgrades needed to support the request.

Once an entity has transmission access as a TC, it must also register as a Market Participant with SPP in order to schedule and settle with SPP. If a REP does not wish to interact directly with SPP for scheduling and settlement purposes, it may designate an agent to act on its behalf (like a QSE in ERCOT). Registering with SPP allows an entity to do business with SPP on the Open Access Same Time Information System (OASIS) and participate in SPP markets.

Duke ... *from 1*

SRA-CD.

The Ohio Consumers' Counsel opposed limiting the bypassabiltiy of Rider SRA-SRT, and the 6% shopping credit, to non-residential customers (Matters, 11/19/08). OCC argued that, by statute, governmental aggregations cannot be charged for standby service. OCC argued Section 4928.143(B)(2)(d), Revised Code, defines standby service to include POLR service, which is essentially what the Capacity Dedication (SRA-CD) rider is.

In its order, PUCO noted that the term "standby service" is not defined by Section 4928.143(B)(2)(d), Revised Code, as the code merely lists the provisions that may be included in an ESP.

PUCO concluded that the legislature's intent was that governmental aggregation customers should not be charged for an electric utility's standing ready to serve those customers at the SSO price if they were to choose to return to SSO, and that such charges are what constitute standby service.

Under this interpretation, PUCO determined that Rider SRA-SRT (Market Capacity Purchases) is a standby service charge because it will compensate Duke for its, "purchase [of] capacity necessary to maintain an offer of firm generation service and [provision of] default service to all consumers in its certified territory;... whether switched or unswitched." Accordingly, residential customers of governmental aggregators should be able to avoid Rider SRA-SRT.

However, Rider SRA-CD (Capacity Dedication) is different, and does not constitute standby service, PUCO ruled. Rider SRA-CD is intended to compensate Duke for providing customers with a first call on its capacity, foregoing the opportunity to sell capacity that is currently dedicated to its standard service offer, permitting customers to switch to competitive suppliers, and assuming the risk associated with maintaining a reasonably stable price during the ESP period. Since Rider SRA-CD does not address the price that the electric utility could charge shopping customers upon returning to the SSO, it does not fall within the Commission's interpretation of standby service, PUCO said. Thus, residential customers of governmental aggregators will not receive the 6% shopping credit equal to Rider SRA-CD.

Under the stipulation, Duke's base generation charge (PTC-BG) will reflect the unbundled generation rate as approved in Case No. 99-1658-EL-ETP less the Regulatory Transition Charge (RTC), adjusted to reflect the following:

a. The RTC for residential customers will be eliminated on December 31, 2008;

b. The RTC for non-residential customers will remain in effect, as an unavoidable charge, through December 31, 2010, and

c. The frozen fuel, purchased power and emission allowances currently recovered in Little "g" (1.2453¢/kWh), will be transferred to the fuel and purchased power rider (Rider PTC-FPP), which won't affect the total price to compare.

Proposed generation rates and shopping credits by rate class can be found in docket 08-920-EL-SSO. The base price of generation will increase approximately 2% in 2009 and 2010 for Duke's residential customers, with no base generation increase in 2011. For commercial and industrial customers, the base price of generation will increase approximately 2% each year of the ESP.

When including updated riders and the quarterly adjustment of Duke's fuel costs, the ESP will result in a decrease in electric rates for all customers for the first quarter of 2009 beginning on Jan. 1, 2009, PUCO said. The decrease for a typical customer is as follows:

- Residential customers (1,000 kWh/month) - 3.8% reduction in the total bill.
- Commercial customers (14,000 kWh/month) - 4.4% reduction in the total bill.
- Industrial customers (400,000 kWh/month with 1 MW demand) - 5% reduction in the total bill

PUCO rejected a provision in the stipulation that limited the ability of mercantile customers to avoid surcharges to fund energy efficiency measures, if mercantile customers undertake such measures on their own, to those customers above 3 MW. PUCO ruled the exemption from the charges should extend to all mercantile customers whose self-directed efficiency measures exceed the applicable benchmark.

The Commission approved the initiation of a collaborative process to design an Electronic Bulletin Board which would promote competitive supply in Duke's service area. The decision does not approve the substance of any design, or the structure of any EBB offerings, that may be developed through the collaboration.