Energy Choice Matters

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National Fuel Gas Asks to Offer Fixed Price Option in New York

National Fuel Gas Distribution Company requested that the New York PSC allow it to again offer a fixed price option (FPO) as a means of lowering customer bills, Distribution said in a plan outlining austerity measures (09-M-0435).

Distribution noted that current NYMEX gas prices are at their lowest since October 2002. Although Distribution's sales customers are receiving the benefit of lower gas costs through the ordinary operation of the gas adjustment clause, "Distribution believes that greater savings might be achieved for customers who elect to enroll in a utility-offered fixed price option."

The Commission first permitted gas utilities to offer a fixed price option in 1997 in response to concerns about volatility in the gas commodity markets. After the fixed price option period expired, the Commission discouraged utility-offered fixed price options in favor of fixed plans offered by ESCOs.

However, Distribution noted that, "The Commission has determined, however, that these extraordinary times justify unconventional actions."

Accordingly, Distribution proposed to again offer a fixed price option on a "limited basis" in order to provide customers with the ability to lock-in lower gas costs, if they remain available.

Distribution suggested that the new fixed price option could generally be designed in accordance with the Commission's 1997 order permitting LDC-offered fixed price options. Under the Commission's October 1997 rehearing order, fixed price options were limited to one year in duration or shorter, and could not be offered to non-core and interruptible customers since those customers have other options to stabilize prices (e.g., switching to oil or purchasing gas supplies from non-utility suppliers). LDCs could also choose to exclude certain low-volume customers from participating in the fixed price option (such as those who use gas for residential cooking only), since the decreased

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NYSEG/RG&E Favor Mandatory Hourly Billing for ESCOs' Hourly Metered Customers

ESCOs should be billed on hourly load data if their customers have hourly meters, NYSEG and Rochester Gas and Electric said in comments on an investigation into advanced metering at the New York PSC (09-M-0074).

A working group had recommended that if an ESCO customer's electric usage is measured by an hourly meter, then the ESCO should be billed on their customer's actual load shape instead of a class average load shape. However, PSC Staff proposed giving ESCOs the option of using actual hourly load, or the class load shape (Matters, 4/15/09).

But NYSEG and RG&E said that giving ESCOs a choice on which load data to use creates, "the potential for gaming in determining whether hourly loads or class loads are more beneficial for each customer."

The use of class load shapes would also increase Unaccounted for Energy, with the associated increased costs socialized, the utilities noted.

NYSEG and RG&E also reported that allowing ESCOs to choose hourly loads or class loads for each customer would be administratively burdensome.

Cerritos Seeks Ruling of Direct Access Rights Under AB 80

The City of Cerritos, California petitioned the California PUC to rule whether Assembly Bill 80 permits Cerritos to conduct an opt-in, direct access aggregation of customers, or requires the use of an opt-out process similar to community choice aggregation under AB 117 (A. 09-06-008).

Cerritos and Southern California Edison have disagreed on Cerritos' rights under AB 80 since implementation. Both agreed, in order to avoid litigation which would have delayed the aggregation's start-up, that Cerritos may provide service to a maximum of 13.02 MW of load on an opt-in basis pending a final ruling from the PUC. However, Cerritos said that it has reached the initial load limit, and is asking the PUC to rule on its rights so that it may serve additional load.

AB 80 was passed by the state legislature in 2002 in response to the suspension of direct access, and allows Cerritos to operate as a "community aggregator." Cerritos argues that a community aggregator is distinct from opt-out community choice aggregators under AB 117, and that it may provide opt-in, direct access service to select customers. SCE argues that Cerritos may only provide opt-out aggregation.

In early 2001, Cerritos initiated an effort to participate in the development of the Magnolia Power Plant in response to the energy crisis, and developed an opt-in, direct access aggregation program to deliver such generation to customers. However, the PUC's issuance of D.01-09-060 suspended direct access, including Cerritos' program.

Thus, Cerritos sponsored AB 80 for the purpose of receiving an exemption from the direct access suspension. The bill defines Cerritos as a "community aggregator," which Cerritos argued is the identical phrase used in AB 1890 (the direct access law, codified at Section 366(c) of the Public Utilities Code) to describe a city that aggregates load within the city and provides opt-in, direct access service.

"The Legislature understood that ... the term 'community aggregator' was a term of art that was used to describe a form of opt-in, direct access service, namely, service introduced and established in AB 1890 that required a 'positive written declaration' (i.e., an 'opt-in') in order to participate," Cerritos said.

Furthermore, Cerritos contended that, because AB 80 refers to Cerritos acting as a community aggregator "notwithstanding" the Commission's suspension of direct access, it is clear that the law provides that Cerritos may operate an opt-in, direct access program.

Cerritos also noted that the PUC "often" used the term "community aggregator" to refer to a form of opt-in, direct access service by a city prior to AB 80.

While SCE believes AB 80 calls for an opt-out aggregation, Cerritos countered that the legislature's use of a different term -- community choice aggregator -- to describe opt-out municipal aggregation belies that argument. Furthermore, AB 80 is silent as to any opt-out process, while AB 117 "painstakingly" enumerated the opt-out process required under community choice aggregation, Cerritos noted.

Cerritos began serving opt-in load, subject to the initial load cap, in 2005. Cerritos currently provides electric service to customers providing a public benefit to the city, serving its own electrical load and the load of the following public benefit customers: Cerritos Community College, ABC Unified School District, Valley Christian School, and certain auto dealerships at the Cerritos Auto Square.

Each year, the load served by Cerritos has increased incrementally, and last year SCE provided notice that Cerritos had exceeded the initial load limit of 13.02 MW. Cerritos responded by implementing a demand reduction measure and by entering into discussions with SCE regarding terms and conditions for a mutually acceptable increase to the initial load limit, though such discussions did not produce a resolution.

The load cap, Cerritos said, is detrimentally affecting the city's ability to provide effective electric service to customers in the city. First, the load limit has forced Cerritos to decline consideration of serving other key public benefit customers.

Additionally, Cerritos has been unable to fully diversify its resource portfolio because of the initial load limit. The load cap compels Cerritos to rely almost exclusively on output from the Magnolia Power Project, as the take-or-pay nature of power plant means that it is economically necessary for Cerritos to first attempt to serve retail load with output from the Magnolia Power Project before any excess is sold in the wholesale market.

As a result, two primary problems occur, Cerritos said. First, since Cerritos uses output from Magnolia almost exclusively to serve its load, Cerritos has no resource diversity. This means that Cerritos is particularly vulnerable to fuel and operating risks. Second, since output from the Magnolia Power Project is base-loaded, while Cerritos' retail load is peak-driven, Cerritos must sell excess output in the wholesale market during all periods except peak periods, which minimizes the value of the Magnolia Power Project.

DPUC Draft Would Reject Minimum Stay for CNG Firm Service

The Connecticut DPUC would reject a proposal from Connecticut Natural Gas to require interruptible customers electing firm service to stay on firm service for three years, under a draft order in CNG's rate case issued yesterday.

CNG had proposed a three-year minimum stay on firm service because it argued, as the supplier of last resort, it must make long-term capacity commitments (due to the constrained Northeast market) to serve such customers -- commitments which may become stranded if customers leave firm service after only one year.

The risk has been exacerbated by a large increase in switching to firm service. Extraordinary market conditions recently seen in the energy markets have made interruptible service (which is priced at the value of service) more expensive than firm service, prompting switching to firm service.

The minimum stay was opposed by marketer Santa Buckley Energy (Matters, 3/20/09).

The DPUC draft dismisses CNG's stranded cost arguments, noting that because the LDC has experienced a significant increase in demand in recent years from a variety of sources, including but not limited to electric generation and customer conversions, CNG would be pursuing additional Northeast capacity regardless of interruptible customer switching.

Since the draft would reject the minimum stay, it would also reject a price cap on interruptible service suggested as an alternative by Santa Buckley Energy, which the marketer had said would discourage price-based switches to firm service and thus make any minimum stay moot. The draft declines to make any changes in the value of service pricing used for interruptible service.

The draft states that, as a general policy, the Department encourages the maximization of interruptible activity as it makes efficient use of secondary capacity, and its associated margins offset the costly infrastructure needed to meet the demand of firm customers. "Requiring these customers to stay on a firm rate for [a] longer period will diminish achievable margin levels and result in less available capacity to serve normal firm growth," the draft says.

The draft notes that CNG retains the discretion to deem a customer ineligible to transfer from interruptible to firm service if doing so would jeopardize the LDC's ability to balance its load.

The proposed decision also declined to address several concerns regarding CNG's Daily Demand Meters cited by Hess.

Among other things, Hess was seeking relief from and reimbursement of balancing charges and related costs imposed on marketers from an eight-year delay in expanding Daily Demand Metering to customers between 5,000 ccf and 30,000 ccf.

The draft only states that the Department expects CNG to diligently pursue its Daily Demand Meter installation program, and would require CNG to file an annual report identifying customers with and without Daily Demand Meters, with an explanation of why each eligible customer does not have a Daily Demand Meter installed.

The draft would not require metering performance standards as proposed by Hess. The proposed decision also does not address Hess' concerns regarding CNG's customer usage estimation methodology, or a usage reporting problem known as "day shifting," in which the correct usage is reported for the wrong day on CNG's website.

GridSolar CPCN Would Reverse Maine Restructuring, Utilities Say

An application by GridSolar LLC for a CPCN as a transmission provider for its 800 MW of distributed generation would "turn restructuring on its head," Bangor Hydro-Electric and Central Maine Power said in memoranda of law filed with the Maine PUC (2009-152).

In seeking a CPCN, GridSolar is arguing that its distributed generation in Central Maine Power's territory is a transmission alternative to CMP's Maine Power Reliability Project since the generation will facilitate reliability in certain load pockets. GridSolar is seeking cost-of-service regulation for the sale of energy, capacity and RECs generated by the GridSolar project through a long-term contract with CMP (Matters, 5/26/09).

However, "GridSolar's distributed generation project cannot, without beggaring the laws of logic and physics, meet the statutory definition of a transmission and distribution (T&D) utility because, contrary to the fundamental premise of the Petition, the mere fact that generation can under some circumstances perform a similar 'reliability function' as transmission does not extinguish the distinctions between them," CMP said.

BHE agreed that GridSolar fits squarely within the definition of a generation asset under the restructuring law, and is no different from any other generator.

"Carried to its conclusion, GridSolar's argument would mean that any load reduction program that uses any sort of equipment to meet peak load demands or any generation unit in a load pocket ... that reduces the need for transmission investment, could also qualify as a T&D utility simply by asserting to the Commission that its facilities were necessary for grid reliability purposes," CMP added.

"Such a finding would swallow the definition of transmission and distribution utility, and destabilize the division between generation and transmission and distribution that forms the basis of the post-restructuring regulatory scheme - not to mention make a lot of energy service companies and generators nervous about potential Commission regulation of their activities," CMP continued.

BHE likewise said that, under GridSolar's logic, there would be no reason not to consider all other generators T&D utilities as well -- "a completely illogical result."

BHE further argued GridSolar is attempting to "exploit" an exception which allows a T&D utility to own limited generation where necessary to support its obligations (such as diesel back-up generators), and said granting GridSolar a CPCN would allow the exception to swallow the rule.

Furthermore, if GridSolar is granted guaranteed cost recovery from ratepayers for a generation project, it will gain a preferred position over other merchant generation, harming the competitive market, BHE added.

ALJ Denies Shell Intervention in SoCalGas/SDG&E Hedging Docket

A California PUC ALJ denied Shell Energy North America's motion to intervene in an application from Southern California Gas Company and San Diego Gas & Electric for approval of their 2009-2010 winter hedging program (A. 09-04-023).

Shell sought intervention to participate in the assessment of whether the utilities' plan is in the best interests of the utilities' core customers, and said it has an interest in participating as it seeks to ensure that the utilities' hedging objectives are consistent with the core procurement objectives articulated in Rulemaking 08-06-025.

However, the ALJ ruled that core customer interests are represented by the Division of Ratepayer Advocates (DRA) and The Utility Reform Network (TURN).

As to hedging policies, the ALJ held that such matters are addressed in proceeding R. 08-06-027. "As Shell Energy is not a SoCalGas or SDG&E core customer and does not represent core customers, intervention in this proceeding to address policy issues is superfluous," the ALJ said.

SoCalGas and SDG&E had alleged that Shell Energy's apparent purpose in intervention was the discovery of confidential information related to previous winter hedging plans.

Briefly:

J.P. Morgan, Sempra Assign Some Ohio Tranches to FirstEnergy Solutions

Several winning bidders in the FirstEnergy Ohio utilities' recent Standard Service Offer auction have assigned a total of 11 tranches to FirstEnergy Solutions, the distribution utilities reported to PUCO. J.P. Morgan Ventures Energy Corp. has assigned to FirstEnergy Solutions two of its six tranches won in the auction for July 2009, and all six of its tranches for August 2009 through May 2011. Sempra Energy Trading has assigned to FirstEnergy Solutions all five of its tranches won in the auction for the entire June 2009 through May 2011 period. FirstEnergy Solutions had won 51 tranches in the auction. Other winning suppliers were American Electric Power Service Corporation (11 tranches), Constellation Energy Commodities Group (10), DTE Energy (1), Duke Energy Ohio, Inc. (5), Dynegy Power Marketing Inc. (10), and PPL EnergyPlus (1).

PUCT Approves Certificate Amendment Recognizing Eagle Industrial Power Services

The PUCT approved an amendment to the REP certificate of TexRep2, LLC to reflect its new ownership under Eagle Industrial Power Services (a subsidiary of wholesale power marketer and QSE Eagle Energy Partners I, LP).

FERC Grants FCM Demand Response M&V Waiver

FERC granted a wavier request sought by several demand response providers which will allow them to file, out-of-time, updated measurement and verification (M&V) plans required by ISO New England Forward Capacity Market rules (ER09-1029, Matters, 5/15/09). The demand response providers have said that, as a result of administrative oversight, every supplier of demand response resources in the ISO-NE Forward Capacity Auction failed to meet a new M&V deadline approved in a series of rule changes at FERC. The Commission stressed its waiver was limited in scope, and declined to require ISO-NE to evaluate its FCM timelines and requirements to ensure that the FCM qualification and auction process is streamlined and clear, as requested by EPSA.

AEP Ohio Signs Long-Term Solar PPA

AEP Ohio has signed a 20-year PPA for all of the output and RECs from a 10.08 MW solar energy facility to be built in Ohio by Wyandot Solar LLC. Commercial operation is expected by mid-summer 2010.

NFG FPO ... *from 1*

benefits those customers would receive under the product could be outweighed by costs to offer the fixed option.

The 1997 rehearing order also gave LDCs discretion to limit fixed price option participation to 10% of customers (or 25% of volumes) by service classification, in order to avoid undue administrative hardship.

Utilities could require that the customer commit to remaining on the fixed price option sales service for the entire term of the product, under the 1997 rehearing order.

Fixed price options under the 1997 rehearing order had to include, at a minimum, the commodity cost of gas, although the Commission expressed a preference for products that would fix all elements of cost (including commodity, capacity, and LDC margin).

Distribution said that it, "recognizes and agrees that the purpose of an FPO is to ameliorate volatility and not necessarily to produce savings. However, an FPO is nonetheless a proven sales item that should be made available as another means of enabling customers to gain greater control over household costs."

Distribution outlined $6.2 million in potential austerity savings. Although none of the cited cost cuts were related to retail access, Distribution did take time to note in its filing that retail access implementation measures are a "leading example" of numerous programs that place upward pressure on its operations and maintenance expenses.

Citing its record of holding down costs, its marginal delivery rate increase in 2007 (with flat rates since), and lower commodity supply prices, Distribution generally objected to the Commission's rationale for mandated austerity measures, noting usage-normalized customer bills on average are lower than they were 12 months ago.

Increased rates are being driven by the legislature's decision to impose new and higher taxes on utility customers (including but limited to the new section 18-a assessment), which arguably renders the resulting increase in utility rates reasonable as a matter of law, Distribution said.

"It should not then be the Commission's role to attempt to relieve customers of the tax burden imposed through the political process by cutting spending for utility purposes. And yet, this is what the [austerity] Notice attempts to do," Distribution said.