Energy Choice Matters

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Mass. Referral Program to Include Specific Offers, but Not Through Phone Calls

Massachusetts electric distribution companies must, "provide more information than strictly a list of names and contact information of participating suppliers," under supplier referral programs, the DPU ruled in an order on model terms and conditions to govern the programs. While utilities will be required to post prices of specific supplier offers on their websites and in bill inserts, the DPU's order will not require utilities to list specific referral offers over the phone, as customers inquiring about competitive supply will instead be directed to a supplier referral page on the utility websites.

The 2008 Green Communities Act required the DPU to institute electric supplier referral programs for residential and small commercial customers. As only reported in *Matters*, the four investor-owned utilities jointly proposed a referral program that would only inform customers of the availability of competitive offers, but would not quote specific prices. Utilities proposed that they should only send supplier lists to customers (Only in Matters, 7/28/09).

Competitive suppliers called the utilities' proposal inconsistent with the Act's requirement that utilities must "describe then available offers." The DPU agreed, and said that the distribution companies must include some description of the participating competitive suppliers' available offers.

Under the DPU's order, offers under the referral program are not standardized, and the order contained no limitation on the type of offer permitted. Offers will be presented in a table listing price, term length, termination fees and other conditions. If a term contract includes automatic renewal, which would require the customer to opt-out in order to return to basic service at the end of the initial

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DPUC Draft Would Maintain 20% Cap on Bilaterally Served Standard Service Load

The Connecticut DPUC would decline to raise the current 20% cap on Standard Service load which may be served under bilateral, long-term contracts, under a draft order released yesterday in the Department's proceeding to provide further guidance on the long-term contracting process (Only in Matters, 6/18/09).

As only reported by *Matters*, both Connecticut Light and Power and United Illuminating have asked the DPUC to allow the utilities to procure more than 20% of Standard Service supplies bilaterally, if conditions are favorable (Only in Matters, 8/31/09).

However, in its draft, the DPUC said that it would be "premature" to adjust the 20% cap on bilateral contracts established in 2008 when the DPUC allowed the use of long-term contracts for Standard Service supplies. The draft says that the Department intends to retain the cap, "until it can gauge the effects of long-term contract procurements."

The DPUC's draft would also decline CL&P's request to waive the requirement that bilateral contracts must be procured in a competitive RFP. CL&P had argued that utilities may encounter opportunities for favorably priced supply outside of an RFP process, and should be allowed to enter into such contracts.

However, the DPUC's draft finds that Standard Service long-term contract procurement is a new

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Rep. Turner Seeks Proration of All Termination Fees

All term contract cancellation fees should be pro-rated over the lifespan of the contract, Rep. Sylvester Turner said in a letter to PUCT Commissioner Kenneth Anderson regarding various customer protection measures.

"There in no equity in treating a customer who fulfills 2 months of a 24 month contract as the same as a customer who cancels 20 months into a 24 month contract," Turner said. A cap on termination fees should also be examined, Turner suggested.

Additionally, Turner said that termination fees should be prohibited for all variable rate and prepay plans. Revised Subst. R. §25.475 prohibits termination fees on residential variable contracts, and any month-to-month contract. Citing offers on Power to Choose, Turner said that, "it does not appear that companies who offer variable rates are charging disconnection/cancellation fees." However, Turner argued that several prepay providers, who define their rate as variable, are charging cancellation fees, or rates Turner argues are *de facto* cancellation fees since they apply to customers who do not stay with the REP for a set term.

Turner cited the Terms of Service for Freedom Power which states, "Our rates for service are variable but will be no greater than the amount charged by the Provider of Last Resort," and that, "upon termination of service(s) from FREEDOM POWER you will be billed a termination fee of $186.00 after service is energized." The Terms of Service describes the charge as for, "the cost of order processing at the time of disconnection or cancellation of service." Turner did not specify where or when Freedom's Terms of Service was accessed (which is relevant as the variable termination fee provision only took effect Aug. 16), but the Terms of Service on Freedom Power's website still contains the language as of Sept. 1.

Turner also criticized a $250 "set-up fee" contained in dPi Energy's Terms of Service. The Terms of Service, as posted on dPi's website Sept. 1, provide that the set-up fee is waived for all new customers that remain at dPi Energy for at least 6 months, and is assessed to customers, "that initiate but terminate service in less than 6 months for any reason." Turner said that such a fee is really a cancellation fee.

Turner's letter also included an excerpt from Bounce Energy's Terms of Service, but Turner did not state what was objectionable in the Terms of Service (nor was it evident from the excerpt, especially with respect to termination fees).

Turner further that said, "it is hard to believe" that customers exiting fixed price contracts prior to the end of their term will truly leave REPs holding power and suffering severe losses.

"[E]lectricity is not a tangible commodity that is unique to the individual customer so that the company will be left holding the product with no ability to offload it to another consumer," although Turner did not explain how a REP that is left holding power supplies which cost perhaps $50/MWh above prevailing rates could find a customer willing to buy this excess power at an above-market price.

Aside from recommendations relating to levelized bill payment plans that are currently in the Substantive Rules, Turner suggested that the Commission explore requiring REPs to provide additional notice of levelized payment arrangements to low-income and fixed-income elderly customers, aside from the notice included in the Terms of Service and Your Rights as a Customer.

In conclusion, Turner said that, "When people have there [sic] electricity turned off because of an inability to pay a high summer bills [sic], the inability to switch to lower rates because of high switching costs, a misunderstanding or misrepresentation of a new product, or fine print in a contract, it creates more animosity towards the deregulated market and offers more arguments that consumers are losing and we should seek re-regulation in the State of Texas."

Draft DPUC Order Finds No New Generation, DSM Currently Needed

A draft Connecticut DPUC decision regarding the state's integrated resource plan would find that the state is not forecast to have a shortage of any energy or capacity requirements during the statutorily defined planning horizon, and that no additional generation or demand side resources should be procured at this time (Only in Matters, 5/5/09).

The DPUC draft affirms the main tenet of the Connecticut Energy Advisory Board's integrated resource plan, which, as only reported in *Matters*, found that no procurement activities are required at this time.

The Department's draft also affirms that there is no need for additional renewable resources either. While CEAB took no position on the renewables issue, the electric distribution companies, in composing their integrated resource plans which are incorporated into the CEAB plan, had recommended the use of long-term procurements of bundled RECs, energy, and capacity to produce lower REC prices for customers, and to help break the link between retail rates and wholesale prices driven by marginal gas-fired plants.

The DPUC draft, however, would conclude that there are sufficient policy instruments to promote the development of new renewable energy: the RPS; projects supported by the Connecticut Clean Energy Fund, including Project 150; and authorization under Docket No. 07-06-61, in which the utilities are allowed, pursuant to Conn. Gen. Stat. § 16-245a(g), to enter into REC contracts lasting between four and ten years. The draft also noted that in open Docket No. 06-01-08RE03, the Department is reviewing a request by the utilities to consider long-term energy or capacity contracts, which may include renewable resources. Thus, there is no need for additional policy instruments through the integrated resource plan to promote new renewable resources at this time, the draft says.

The draft would affirm the DPUC's prior findings that the risks of any proposed alternatives to the New England East-West Solution (NEEWS) transmission line at this late stage are extremely high. Accordingly, the DPUC believes at this late date that it would be extremely difficult to develop alternatives to NEEWS that would have sufficient certainty of development and that would address the same needs as NEEWS.

The DPUC would also reject the utilities' recommendations to significantly ramp up demand side management expenditures in advance of the year of need under the integrated resource plan. The DPUC intends to examine the issue of demand side management goal-setting and planning in reviewing the 2010 integrated resource plan, after the 2010 Conservation and Load Management plan and integrated resource plan have been submitted.

Briefly:

Champion Energy Services Applies for Ohio Electric License

Champion Energy Services applied for an Ohio competitive retail electric supplier license to serve commercial, mercantile and industrial customers at the three FirstEnergy distribution companies. Champion said it would focus on serving small and medium businesses. Champion, which operates in Texas and Illinois, reported that it has a peak load of almost 900 MW. Champion is currently seeking electric supplier licenses in Pennsylvania and New Jersey (Only in Matters, 8/12/09).

PP&U Reports Revenues, Load

Public Power & Utility reported that its 2008 gross receipts from Connecticut electric sales were $14.4 million, and it estimated 2009 gross receipts at $42.5 million, in a compliance filing with the Connecticut DPUC. PP&U said it expects to serve 765,000 MWh of load in the next 12 months. The filing was made in response to a DPUC inquiry regarding PP&U’s compliance with bonding requirements (Matters, 8/25/09).

Citizens Electric Files Updated Generation Rate

Citizens Electric Company filed an updated generation service supply rate of 9.5399¢/kWh with the Pennsylvania PUC, for the three-month period beginning October 1. The current rate is 7.4230¢/kWh.

DEFG Seeking Respondents for Restructuring Survey

Distributed Energy Financial Group invited stakeholders to complete its online survey on electric industry restructuring, which asks respondents about the success of various markets and optimal market structure, as well future price expectations and value-added on-site services. The survey will be used as part of DEFG's Annual Baseline Assessment of Choice in Canada and the United States. Click here for the survey, or it can be accessed from the defgllc.com home page.

NERA Launches PSE&G S-REC Auction Site
NERA Economic Consulting announced the launch of a website to support quarterly auctions of solar RECs by Public Service Electric and Gas which are received as repayments for loans extended by PSE&G to develop solar energy projects (www.solarREC-auction.com). The first auction is scheduled for January 29, 2010.

Advantage IQ Acquires Ecos Consulting
Broker-consultant Advantage IQ has acquired Ecos Consulting, which provides energy efficiency and green marketing solutions.

PJM Proposes to Base CONE on Handy-Whitman Index

PJM has filed tariff changes at FERC to eliminate the current empirical Cost of New Entry (CONE) in the Reliability Pricing Model and replace it with a new provision that adjusts CONE each year in accordance with changes in the Handy-Whitman Index of Public Utility Construction Costs. The change in CONE methodology is among several non-consensus proposals PJM submitted in a required Sept. 1 compliance filing.

Under PJM's new proposal for setting CONE, every Delivery Year, for each CONE Area, PJM will adjust the CONE used in the Base Residual Auction in the prior Delivery Year by the most recent twelve-month rate of change in the applicable Handy-Whitman Index, determined at the time that the CONE must be posted for that Delivery Year's Base Residual Auction.

Additionally, PJM filed to replace the current triennial CONE review process with a new procedure based on offers actually submitted in the RPM Base Residual Auctions for new entry generators. After the Handy-Whitman Index adjustment method has been in place for four Base Residual Auctions, and every four years thereafter, PJM will conduct a comprehensive review of the Cost of New Entry based on (i) clearing prices in the RPM auctions that cleared new entry offers and (ii) the offers for new entry by resources of the same type as the then-effective Reference Resource submitted in the four preceding Base Residual Auctions.

Notably, a new entry offer will be considered whether or not it cleared in the auction, but offers that do not clear will be considered only if the offer was competitive, as determined in accordance with "objective criteria and evidence." Specifically, PJM proposed that offers will be deemed non-competitive if (among other reasons) any portion of the offer includes any uncompetitive distortion, such as direct subsidies, preferential financing, or feed-in tariffs.

Such an auction-based analysis must be completed within three months after the last Base Residual Auction in the study. If the analysis calculates a CONE value that is within ten percent of the CONE value expected (based on the latest Handy-Whitman Index data) for the next BRA, then no other adjustment is required. In that case, the Handy-Whitman Index approach will simply continue to govern annual changes to CONE.

However, if the auction-based analysis indicates a change of more than ten percent for any CONE Area, then PJM will institute a process leading to a tariff-change filing with FERC to propose new CONE values for all CONE Areas. PJM would also undertake a review of the plant type assumed for the Reference Resource (e.g., from a combustion turbine to a combined cycle). In those circumstances, PJM also would commission an independent estimate, by an outside expert, of the fixed costs to install a new entry generator, to provide stakeholders with additional information on the current Cost of New Entry.

Based on the results of the auction analysis, PJM staff will propose new CONE values by September 1 of the calendar year before the next Base Residual Auction. Stakeholders will then have two months to consider the proposed values and either endorse them or propose alternate values. The PJM Board of Managers will then consider the CONE values, and PJM will file new values with the Commission no later than December 1 of the calendar year before the next Base Residual Auction.

PJM also filed to revise the current triennial review procedures for the Variable Resource Requirement (VRR) Curve shape and other VRR Curve parameters, to conform those to the review schedule proposed for changes to CONE. "This ensures that comprehensive reviews of the VRR Curve and its major parameters occur at the same time and on the same schedule," PJM said.

PJM argued that the Handy-Whitman Index approach promotes stability and predictability. "Historically, the H-W Indices have not experienced dramatic real-price changes from year-to-year, yet they provide an industry-trusted indication of the direction and approximate degree of changes in generation plant construction costs," PJM said.

Incremental Auctions

PJM sought to revise its tariff to provide that 0.5% of capacity will be sought in each of the First and Second Incremental Auctions, and that 1.5% will be sought in the Third Incremental Auction (for a total 2.5% holdback). By procuring 60% of the holdback in the Third Incremental Auction (e.g. 1.5% of total capacity), a substantial amount of short lead-time resources will be given a reasonable opportunity to participate in the final incremental auction, PJM said.

PJM, as directed by FERC, also addressed arguments from the Illinois Commerce Commission, which has called for reciprocal treatment regarding incremental auctions (Only in Matters, 8/17/09). The ICC has argued that if PJM includes the uncleared portion of the VRR curve in the Incremental Auctions in certain circumstances when committed capacity falls short of the Reliability Requirement, then PJM should offer to sell back capacity when the committed capacity exceeds the Reliability Requirement.

PJM replied that, "The Illinois Commission's position effectively rejects a fundamental purpose of RPM's sloped demand curve. The VRR Curve can result in commitment of capacity in excess of the target reliability requirement when that is the least-cost overall solution. The [federal] Commission has expressly approved the VRR Curve for PJM and similar demand curves for other capacity markets based on evidence that they should result in greater reliability at lower cost over time," PJM said.

"If, however, all capacity procured in excess of the reliability requirement in the base auction was sold back in the incremental auction, an essential attribute of the VRR Curve would be eliminated. Capacity above the target reliability requirement would be devalued; the former approach of using a vertical demand curve would effectively be reinstated; and reliability and cost would both likely be adversely affected," PJM claimed.

PJM did propose several tweaks designed to mitigate the ICC's concerns, including raising the trigger for additional procurement from a 100 MW shortfall below the Reliability Requirement to a 500 MW shortfall below the Reliability Requirement.

PJM also said that it is still evaluating a sell-back provision for "conditional" incremental auctions, which are auctions used to procure additional capacity if modeled transmission lines are not built on time. Aside from leaving zones relying on transmission imports with less capacity than needed, such transmission line delays will also create excess capacity in the zones where the exports were to have originated.

Consensus Revisions

PJM also submitted in a separate filing consensus changes to the RPM tariffs, agreed to in the Capacity Market Evolution Committee.

Among other things, PJM would revise the New Entry Pricing Adjustment (NEPA) so that a new entrant needed in the first delivery year can be assured of three years of revenue under the adjustment, to incent the needed new entry. Specifically, if the NEPA resource does not clear the auction in the second or third year, the resource is deemed resubmitted at the highest price per MW at which the amount of capacity it cleared in the first year will clear in the subsequent year. The NEPA resource may displace one or more other resources in the supply stack that otherwise would have cleared, but it will do so at a price that is low enough to displace those other resources (but no lower than needed for that purpose). The NEPA resources will not set the auction clearing price in such circumstances.

Stakeholders also agreed to changes that will allow demand resources to set the clearing price in the RPM auctions. As part of the revisions, demand resources will not be considered part of the available supply for purposes of applying the market power screens to generation resources.

PJM also proposed a new "Excess Commitment Credit" for Load-Serving Entities in certain circumstances. Under this mechanism, PJM will allocate to Load Serving Entities, for use as replacement capacity, the megawatt quantity of any Sell Offers submitted by PJM in the Incremental Auctions that did not clear. PJM Sell Offers in the Incremental Auctions are an attempt to "un-commit" capacity that is no longer needed due to a change in circumstances such as a load forecast reduction. "There is no guarantee, however, that all such offers will be matched by offers from parties that are seeking to be relieved of their prior capacity commitments," PJM said, in which case LSEs would be allocated a share of the remaining "excess" capacity as replacement capacity. LSEs could use replacement capacity to mitigate their own risks of resource nonperformance, or could offer to sell replacement capacity to others.

NRG Calls MISO Firm Redirect Proposal an Attempt to Enhance TO Revenue

Circumstances suggest that the Midwest ISO's proposed revisions to rules governing changes in Receipt and Delivery Points on a firm basis (firm redirects), which MISO claims are needed to prevent the gaming of a "loophole," are simply a response to "pressure from transmission owners seeking to increase their transmission revenues by changing the rules after four years of successful market operations," the NRG Companies alleged at FERC.

As only reported by *Matters*, MISO has proposed that for firm redirects that would result in a lower transmission rate, the customer shall be charged the applicable transmission rate, plus the difference between the lower rate and rate for the original path. The change is meant to eliminate firm redirects which result in a lower transmission rate, particularly a rate of $0 as is the case with redirects to PJM -- behavior MISO termed as questionable and opportunistic, resulting in market inefficiencies (Matters, 8/12/09).

However, NRG countered that the ability to redirect long-term transmission service to lower-cost Points of Delivery is a legitimate business tool used by LSEs reduce costs to end-use customers, and thus should be preserved under the existing Midwest ISO Tariff. NRG said that the ability to redirect transmission to a zero cost Point of Delivery has saved its end-use customers many millions of dollars.

"Simply put, buying the cheapest, most economic, power is not gaming - nor is buying and utilizing transmission service only when it is economic to do so," NRG said. According to NRG, the ability to redirect transmission service to lower-cost Points of Delivery allows transmission service customers to: (i) mitigate the costs of long-term transmission outages and curtailments; (ii) economically optimize their resource portfolio; and (iii) ensure access to sufficient generation reserve in order to serve native load customers.

Cargill Power Markets also protested MISO's proposal, noting a similar higher-of pricing regime was rejected by the Commission previously. "[T]he Midwest ISO's proposal may result in over-recovery of revenue, will unnecessarily reduce firm Available Transfer Capability, will result in undue discrimination, lacks the necessary Part 35 cost support and justification, and would reinstitute rate pancaking when wheeling from the Midwest ISO into PJM," Cargill said. Allete and DTE Energy Trading filed similar protests.

The Midwest ISO Transmission Owners supported MISO's proposed changes since, "[t]he pervasive use of the redirect procedure by some Transmission Customers to avoid paying transmission charges by parking their Point-to-Point service on zero-rate or low-rate interfaces when not needed on the original paths has harmed Transmission Owners by reducing transmission revenues to which they are entitled under the Midwest ISO Tariff." The Midwest TDUs supported MISO's filing as well.

Duke Updates Rider PTC-AAC

Duke Energy Ohio applied to update bypassable Rider PTC-AAC (annually adjusted component), which recovers costs associated with environmental compliance, changes in taxes, Homeland Security, and fuel flexibility. Additionally, Duke proposed moving environmental reagent costs from Rider PTC-AAC to bypassable Rider PTC-FPP (fuel and purchased power), which is reconciled quarterly rather than annually. Proposed new Rider PTC-AAC rates for selected classes are below. Prices for additional rate classes may be found in docket 09-0770-EL-UNC. The prices below presume that environmental reagent costs are removed from Rider PTC-AAC.

	PTC-AAC Charge Per kW/kWh
Rate RS, Residential Service	
Summer, First 1000 kWh	$0.008966
Summer, Additional kWh	$0.011360
Winter, First 1000 kWh	$0.008966
Winter, Additional kWh	$0.003382
Rate DS, Service at Secondary Distribution Voltage	
First 1000 kW	$1.553700
Additional kW	$1.229000
Billing Demand Times 300	$0.003974
Additional kWh	$0.003301
Rate DM, Secondary Distribution Service Small	
Summer, First 2800 kWh	$0.011884
Summer, Next 3200 kWh	$0.003034
Summer, Additional kWh	$0.001322
Winter. First 2800 kWh	$0.009432
Winter, Next 3200 kWh	$0.003037
Winter, Additional kWh	$0.001255
Rate DP, Service at Primary Distribution Voltage	
First 1000 kW	$1.403200
Additional kW	$1.106900
Billing Demand Times 300	$0.004474
Additional kWh	$0.003588
Rate TS, Service at Transmission Voltage	
First 50,000 kVa	$1.701100
Additional kVa	$1.226300
Billing Demand Times 300	$0.002922
Additional kWh	$0.003325

Mass. Referral ... *from 1*

term, the supplier offer must be notated with an asterisk.

The table of offers will be posted on a dedicated "Competitive Supply" webpage on each utility's website. A disclaimer at the bottom of each table would include the statement, "Contracts with Competitive Suppliers may be subject to certain risks and/or penalties not fully described in the information above."

The Department said that requiring the disclosure of certain conditions such as termination fees, "will ensure reasonable disclosure of competitive supply offers to customers, providing customers with sufficient information to inform initial comparisons of available electricity offers."

When customers call the utility to either (a) initiate new utility service; (b) reinstate service following a change of residence or business location; (c) make an inquiry regarding their rates; or (d) seek information regarding energy efficiency, the utility shall offer customers the option to learn about their electricity supply options. Customers expressing an interest in learning more about competitive supply will be directed to a specific utility webpage where the supplier referral offers are located. If a customer is interested in an offer listed on the webpage, the customer can then contact the competitive supplier directly by telephone or by clicking on a live link in the table that will take the customer to the competitive supplier's website.

If a customer does not have access to the Competitive Supply webpage, the utility’s customer service representative shall arrange to mail a printed version of the table to the customer, the DPU said.

Offers from participating suppliers are due to the utility in writing electronically five days before the end of each month for posting on the first day of the following month. Such notification shall be required even if there is no change in the competitive supplier's electric offers from the prior month.

The Department is also requiring that each distribution company maintain "a clear and obvious link" to the Competitive Supply webpage on its homepage.

Each utility shall propose for Department approval an appropriate script for directing customers to the Competitive Supply webpage.

The DPU said that its adopted method of disseminating supplier offers will ensure that customers are reasonably informed of the electric offers without requiring the active involvement of, or an undue administrative burden on, the distribution companies. Directing customers to detailed tables comparing supplier prices, terms and conditions is superior to quoting simply the price and term length of an offer over the phone through an interactive voice response system, the Department concluded. The DPU said that its method further addresses the Attorney General's concern about potential unfair and deceptive trade practices because the utilities will simply be presenting terms and conditions of competitive supply offers as presented by the participating suppliers.

The DPU will also require utilities to include a bill insert containing the table of competitive supplier offers (with contact information) every four months. Twice annually, in months where there is no competitive supply insert, utilities are to include a bill message inviting customers to contact the utility for information about competitive supply, along with the appropriate phone number and link to the Competitive Supply webpage, to the extent space is available on the bill.

Suppliers participating in the referral program shall bear incremental costs of disseminating supplier offers, the DPU held, but costs shall also be "reasonable and transparent." The extent of costs should also be reported to competitive suppliers prior to suppliers participating in the program, the Department said. Incremental costs will likely be lower than earlier projections since the DPU's referral program will not require changes to the utilities' interactive voice response systems.

The DPU declined to order any changes in the fixed-to-variable recalculation applicable to smaller customers leaving basic service, citing little evidence that the recalculation requirement will be a barrier to successful dissemination of information regarding available supply offers.

Suppliers are not required to list their offers on the referral websites, and participating suppliers may continue to make additional offers available to customers outside of the referral program.

Conn. Bilaterals ... *from 1*

process. While the procurements will hopefully prove to be beneficial, "little is known at this time as to whether the initiative will succeed in lowering Standard Service prices, or in distancing Standard Service pricing from the influences of ISO-NE day-ahead markets," the draft says. Relaxing the competitive RFP requirement is not appropriate under such circumstances, the draft holds.

The DPUC draft would not prohibit bidding by affiliates of the distribution utilities in the bilateral RFPs. However, a utility can only entertain bids from an unregulated affiliate if it first seeks approval of the Department, at which time the utility will be required to demonstrate that adequate safeguards have been, and will be, implemented to ensure against favoritism, and that all FERC requirements will be met.

Under the draft, most bilateral contracts will be reviewed under an expedited, yet full review of the evidentiary record, which includes hearings, briefs, reply briefs and written exceptions. No firm deadline would be set. The draft says it would allow for consideration of a mechanism that adjusts prices for market risks associated with open-ended bids only in the event that the approval process takes longer than six weeks

For bilateral energy-only contracts two to five years in length that are benchmarked against forward energy prices, the draft would commit the DPUC to issuing an order on the contracts on the same day an application is filed, provided that the application is received before 9:00 a.m.

The draft decision would affirm the DPUC's early draft procedural ruling which found that an analysis regarding Standard Service migration risk is not required as part of the bilateral procurement. The draft noted that the purpose of a migration study would be to allow the Department to reject proposed long-term contracts if their adoption would cause ingress to Standard Service from competitive load. However, the language of Conn. Gen. Stat. § 16-244c(n) permits utilities to enter into long-term contracts, but does not condition their procurement upon the presence or absence of migration. "Imposing a migration study requirement would effectively place the Department in the role of reconsidering policy conclusions already reached by the General Assembly," the draft says.

Since the DPUC has found in its integrated resource plan that there is no need for additional capacity in the near future, the Department would not typically evaluate non-price benefits of bilateral contracts submitted. The procurements, the DPUC stressed, are intended to lower the cost of Standard Service power, and not obtain new generation or achieve peak reduction goals. Additional benefits may considered as a tie breaker between alternative proposals, the draft says.

Although the draft does not expect that contracts which pass through the risk of changes in the price of natural gas to customers would provide meaningful benefits, the Department would not preclude such contracts from the procurement under the draft.

The DPUC would publicly disclose a description of the bids, except for the name of the bidder, during the course of the proceeding. One year after the procurement is completed, the Department would release the name(s) of the winning bidder(s). Contract price and other terms and conditions of the winning contract(s) would not be protected. The names of unsuccessful bidders would not be released.