RESA St. 1-SR

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Petition of Duquesne Light Company for	:	
Approval of a Default Service Program and	:	Docket No. P-2014-2418242
Procurement Plan for the Period June 1, 2015	:	
through May 31, 2017	:	
	:	

SURREBUTTAL TESTIMONY

OF

RICHARD J. HUDSON, JR.

On Behalf of

Retail Energy Supply Association

August 15, 2014

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I. INTRODUCTION AND BACKGROUND

Q. PLEASE STATE YOUR NAME AND TITLE.

A. My name is Richard J. Hudson, Jr. and I am the Pennsylvania State Chairman for the Retail Energy Supply Association ("RESA").[1]

Q. HAVE YOU PREVIOUSLY SUBMITTED TESTIMONY IN THIS PROCEEDING?

A. Yes. I submitted direct testimony marked as RESA St. No. 1 and rebuttal testimony marked as RESA St. No. 1-R on behalf of RESA regarding the proposal submitted by Duquesne Light Company ("Duquesne").

Q. WHAT IS THE PURPOSE OF YOUR SURREBUTTAL TESTIMONY?

A. The purpose of this testimony is to respond to: (1) rebuttal testimony from Duquesne, OCA, and OSBA regarding the default service procurement plans for all customer classes; (2) rebuttal testimony from Duquesne regarding default service related costs; (3) rebuttal testimony from Duquesne regarding the standard offer program; and (4) rebuttal testimony from Duquesne regarding market-based charges.

[1] RESA's members include: AEP Energy, Inc.; Champion Energy Services, LLC; Consolidated Edison Solutions, Inc.; Constellation NewEnergy, Inc.; Direct Energy Services, LLC; GDF SUEZ Energy Resources NA, Inc.; Homefield Energy; IDT Energy, Inc.; Integrys Energy Services, Inc.; Interstate Gas Supply, Inc. dba IGS Energy; Just Energy; Liberty Power; MC Squared Energy Services, LLC; Mint Energy, LLC; NextEra Energy Services; Noble Americas Energy Solutions LLC; NRG Energy, Inc.; PPL EnergyPlus, LLC; Stream Energy; TransCanada Power Marketing Ltd. and TriEagle Energy, L.P. The comments expressed in this filing represent only those of RESA as an organization and not necessarily the views of each particular RESA member.

II. PROCUREMENT PLAN DESIGN

(A) RESA recommends that the Commission add 6-month and 3-month supply contracts to Duquesne's proposed residential and small C&I customer portfolio.

Q. DOES DUQUESNE RAISE OBJECTIONS TO YOUR SUGGESTION TO REPLACE TWO 12-MONTH PROCUREMENT CONTRACTS WITH 6-MONTH AND 3-MONTH CONTRACTS FOR RESIDENTIAL AND SMALL COMMERCIAL CUSTOMERS?

A. Yes. Duquesne Witnesses Habberfield and Fisher testify that RESA has proposed a procurement plan for residential and small C&I customers that includes more shorter-term procurement contracts that Duquesne's proposal, and OCA's proposal includes procurement contracts longer in duration. Since Duquesne's plan is the "middle ground," it must be reasonable, according to Mr. Habberfield and Mr. Fisher. Moreover, Duquesne contends that, despite RESA's claims to the contrary, Duquesne's proposal is indeed "market based," that RESA's proposal would eliminate the "overhang" at the end of plan period, and that default service rates that can deviate from underlying market prices do not discourage competition.

Q. DOES OCA ALSO OPPOSE YOUR RECOMMENDATIONS FOR RESIDENTIAL CUSTOMERS?

A. Yes. Similar to the objections raised by Duquesne, OCA Witness Estomin expresses concern that RESA's proposal would "result in a residential Default Service portfolio that is characterized by more price instability than" Duquesne's proposal, and that OCA's 2-year contracts are market based contracts. Mr. Estomin contends that the competitive market benefits from stable default service prices, and that increased price stability within the residential Default Service portfolio can help EGSs attract residential load. (OCA Statement No. 1-R at 3-4).

Q. HOW DO YOU RESPOND?

A. As an initial observation, I would note that there is no dispute that my recommendation to incorporate shorter term 6-month and 3-month contracts in the procurement mix is more consistent with the Commission's stated objective in the *End State Order*.[2]

Q. WHAT IS YOUR RESPONSE TO DUQUESNE'S AND OCA'S TESTIMONY THAT THEIR PROPOSALS ARE "MARKET BASED" AND THAT RESA INCORRECTLY ARGUES THAT ITS PROPOSAL IS MORE MARKET REFLECTIVE THAN DUQUESNE'S OR OCA'S PROPOSALS?

A. There seems to be some confusion about my earlier testimony, so let me try to explain. Mr. Fisher's main dispute seems to be with the use of the phrase "more market based" to describe RESA's preference for shorter term procurement products. However, the phrases "market based" and "market responsive" are general terms used at times interchangeably to convey a relatively simple concept—that shorter term procurement products better reflect contemporaneous market prices and conditions than longer term contracts. There is clearly a greater degree of market responsiveness to a 3-month contract versus a 10-year contract because the former will better reflect contemporaneous market prices and conditions. The Commission itself uses similar language in describing its *End State Order* recommendations: "*Consequently, the Commission's main goal in developing a revised default service product is to create a* ***more market-based*** *PTC."*(*End State Order* at 24) (emphasis added). I do not disagree that the 12-month and 24-month procurement contracts proposed by Duquesne and OCA, respectively, can be "market based" at the time that those respective contracts are bid upon by wholesale suppliers. Indeed, any contract entered

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[2] *Investigation of Pennsylvania's Retail Electricity Market: End State of Default Service*, Docket No. 1-2011-2237952, Final Order entered February 15, 2013 ("*End State Order*").

into between a willing buyer and a willing seller could be considered a "market based" contract. However, over time, the default service prices that those longer term contracts yield are not likely to reflect, and history has shown that they will not reflect, ongoing contemporaneous market prices and conditions. The longer the procurement contract, the more likely it will become out-of-market during the time that the contract is in effect. In other words, longer-term contracts such as those proposed by Duquesne and OCA result in a lag between the default service price, which would have been established months or even years earlier, and prevailing market prices on a given day that the longer-term contract is in effect. RESA's proposal to inject 6-month and 3-month contracts into the residential and small C&I portfolio will result in default service prices that better reflect market prices on each day of the plan period than Duquesne's or OCA's proposals. This is important to the continued growth and development of the competitive market because EGSs are making offers every day, not just on the days that default service contracts are procured and the Price to Compare is set. As I stated in my previous testimony, default service rates that continuously reflect market conditions foster sustainable and robust retail competition by eliminating the boom/bust cycles that prohibit the growth of competition.

Q. WHAT IS YOUR RESPONSE TO DUQUESNE'S AND OCA'S TESTIMONY THAT PRICE STABILITY IS NEEDED FOR THE RESIDENTIAL DEFAULT SERVICE PLAN?

A. In my opinion, these arguments place too much emphasis on just one component of pricing – its ability to change. While I do not necessarily dispute that some consumers may value price stability – even if that stable price is higher than the market price – over a changing price, I do not agree that the default service provider should be charged with creating that product. The Commission's *End State Order* favored a more market responsive default service product.

Q. HOW DO YOU RESPOND TO DUQUESNE AND OCA'S ARGUMENTS THAT INCREASED DEFAULT SERVICE PRICE STABILITY WITHIN THE RESIDENTIAL DEFAULT SERVICE PORTFOLIO CAN HELP EGSS ATTRACT RESIDENTIAL LOAD?

A. One should carefully examine the underlying premise of this argument—essentially that stable and ***high*** default service prices are good for competition. I do not dispute the fact that, at times, competition can develop in situations where the default service price to compare is fixed for longer periods of time. But the argument that this helps EGSs to compete to acquire customers is flawed as a matter of long term policy. Of course, if the "stable" default service price is substantially above current market prices, this can create an opportunity for EGSs to make attractive offers to customers. But the question is whether this is good policy for customers or EGSs in the long run. Default service prices that are high, but stable, was exactly what happened in Duquesne's service territory several years ago when customers had a 29-month fixed rate that was priced significantly above market, leading to too many Duquesne ratepayers paying too much for their electricity because they remained on default service.[3] Conversely, the Commission has cautioned about "bust" cycles of competition, citing to 2001, when market prices rose and EGSs could not compete with an "artificially depressed" PTC. RESA's position is that EGSs should compete,

[3] Commissioner Cawley has recognized that Duquesne's 29-month static price turned out to be well above market prices, and that "many suppliers logically entered the market, providing much lower, more market-based pricing to residential customers." Yet, many customers continued to take default service from Duquesne and paid up to 35% more for their energy supply, which "is not just and reasonable." *RMI Investigation*, Docket No. 1-2011-2237952, Concurring and Dissenting Statement of Commissioner Cawley at 2 (Sept. 27, 2012).

and win customers, based on numerous factors, but competing against a default service that is not reflective of current market conditions will not result in long-term continuous or sustainable competition and is not a satisfactory default service structure.

Moreover, no one disputes that RESA's proposals for residential and, for that matter, other customer classes, are more in line with the Commission's policy positions in the *End State Order*. Even Duquesne admits, as it must, that the Commission in the *End State Order* proposed that residential and small C&I customers be supplied entirely with 90-day products. (Duquesne Statement No. R-3 at 13). RESA's proposal for residential and small C&I procurements includes 50% 3-month contracts (and a 50% 12-month contract) during the last six months of the plan period, which is not a full transition to 90-day contracts but a beginning transition towards the Commission's desired end state.

Q. DUQUESNE WITNESS FISHER POSES A HYPOTHETICAL INVOLVING "MARKET BASED" MORTGAGE RATES. (SEE DUQUESNE STATEMENT NO. R-3 AT 8-9). DO YOU HAVE A RESPONSE TO HIS TESTIMONY?

A. Yes. Mr. Fisher introduces this hypothetical to try to explain why my testimony about default service procurement contracts being "market based" is in error. I address that apparent misunderstanding of my testimony above. In addition, I do not believe that comparing a short-term versus a long-term mortgage is a valid analogy for a wholesale electricity supply contract. Mortgages of different term lengths are all standard products that are transparently referenced in the financial industry. One need only visit a website like www.bankrate.com, to easily compare interest rates for standard mortgage products like 30-year fixed, 15-year fixed and 5/1 adjustable rate mortgages.

However, multi-year, full requirements, fixed price wholesale energy contracts are not standard, liquidly traded products in wholesale energy markets. These products are either bilaterally negotiated, or they are bid out through a complex, structured RFP process such as an EDC's DSP. Furthermore, there is no "default mortgage rate" against which all market participants must compete, and there is no legacy monopoly mortgage company that still serves over 50% of homeowners.

Q. WHAT IS YOUR RESPONSE TO CONCERNS THAT RESA'S SUGGESTED RESIDENTIAL AND SMALL C&I PORTFOLIO WOULD CREATE A HARD STOP OF ALL SUPPLY CONTRACTS AT THE END OF THE PLAN PERIOD?

A. RESA does not support the use of default service contracts that extend beyond the expiration date of the default service plan. As explained in my direct testimony, the presence of these contracts is likely to be a hindrance to the Commission's efforts to establish and implement a new default service structure following the current DSP plan term, should the Commission choose to do so. RESA has recommended that the Commission take the same approach in the upcoming plan period that it took for the current plan period by not including "overhang" contracts in the portfolio.

Q. HOW DO YOU RESPOND TO THE CLAIM THAT INJECTING 6-MONTH AND 3-MONTH CONTRACTS INTO THE RESIDENTIAL AND SMALL C&I PORTFOLIO WOULD RESULT IN UNREASONABLY VOLATILE DEFAULT SERVICE PRICING?

A. I believe my recommended procurement approach does appropriately balance the interest of price stability with other policy objectives, such as ensuring a market responsive default service rate. The two 6-month and two 3-month full requirements products that would replace two of Duquesne's proposed 12-month products are still fixed price products. Also, RESA's proposal maintains a level of price stability because during the last six months of the plan period 50% of the load would be served by an existing 12-month contract and 50% would be served by 3-month contracts.[4] This is greater price stability relative to other options, such as 100% quarterly contracts as the Commission envisioned in its *End State Order* for residential and small C&I customers. My proposal does not transition these customers all the way to the Commission's desired end state but paves the way for that result in the next plan period.

Q. IN FURTHER ADDRESSING THE PRICE STABILITY ARGUMENT, MR. FISHER CITES THE EVENTS OF THE POLAR VORTEX AND A REPORT PRODUCED BY CONEDISON SOLUTIONS AS SUPPORT FOR DUQUESNE'S OPPOSITION TO SHORTER TERM CONTRACTS AS RECOMMENDED BY RESA. DO YOU AGREE WITH THESE CLAIMS?

A. A. No. Mr. Fisher attempts to use the report produced by ConEdison Solutions as evidence of market price volatility in wholesale electricity markets. I do not dispute the fact that wholesale electricity markets exhibit price volatility. However, this does not mean that shorter term, full requirements fixed price contracts, such as the 3-month and 6-month contracts that I recommend, will translate into the same level of price volatility to customers remaining on default service. The price volatility experienced during the Polar Vortex primarily manifested in significant increases in spot market energy prices (LMPs) and related ancillary services in the PJM administered markets. RESA is not recommending spot market pricing for residential or small C&I customers, nor is RESA recommending 100 percent 3-month, full requirements contracts for these customers. RESA is recommending including some 3- and 6-month fixed price contracts in the portfolio. One can look to the experience with such

[4] See RESA Statement No. 1-R at 2 and RESA Exhibit RJH-6 attached thereto.

shorter term contracts in Maryland under their Type II standard offer service ("SOS") structure to see that such contracts have not resulted in the type of extreme price volatility that Mr. Fisher implies with his reference to the Polar Vortex events. For example, the recent Type II price changes for Baltimore Gas and Electric Company ("BGE") are shown below. Although the 3-month contracts for the March to May 2014 period were procured in the very middle of the Polar Vortex, the resulting price change (11.3 percent) compared to the immediately previous pricing period was relatively modest given the extremely anomalous market conditions occurring at the time.

Recent price changes for Schedule G Type II SOS customers			
December 2013 to February 2014 (procured on October 28, 2013)	March 2014 to May 2014 (procured on January 27, 2014)	June 2014 to August 2014 (procured on April 21, 2014)	September 2014 to November 2014 (procured on June 9, 2014)
8.554 cents/kWh	9.523 cents/kWh	9.618 cents/kWh	7.968 cents/kWh

Q. IS MR. FISHER'S CONCERN ABOUT THE POLAR VORTEX ACTUALLY A REASON TO USE SHORTER TERM CONTRACTS AS OPPOSED TO LONGER TERM CONTRACTS?

A. Yes. The extreme cold experienced during the Polar Vortex was an anomalous situation that was driven by a number of factors including record cold temperatures. Although the ConEdison Solutions report cited by Mr. Fisher does discuss the likelihood of potentially high winter prices in future years, it also points out in several places that the Polar Vortex situation was a unique and anomalous culmination of circumstances:

- "…this has been one of the coldest winters east of the Rockies in recent history." (page 2);
- "It's not surprising then that electricity demand hit record highs this winter." (page 2).

The paper also goes on to state, after the section quoted in Mr. Fisher's testimony, that future prices will depend on various circumstances: "Whether prices will be higher or lower than this winter will depend on a number of factors, including the severity and duration of cold weather." (page 3). Mr. Fisher's attempt to paint this whitepaper as an argument that we will experience Polar Vortex conditions on an ongoing basis is simply incorrect. Furthermore, if one examines Mr. Fisher's logic, his concern over the Polar Vortex, and similar market disrupting events that may occur in the future, is actually a good reason to use more market responsive contracts as RESA recommends. Longer term contracts procured during or soon after extreme market conditions will lock in the resulting higher market prices for a longer period of time with longer lasting impacts to customers. One can never predict when a disruptive event will occur, so regardless of when a solicitation event is scheduled, there is some risk that it may occur during a period of unusual market conditions. However, a shorter term contract will allow prices to moderate as market conditions normalize. As shown in the table above, although the Type II Maryland SOS prices did increase during the March 2014 to May 2014 period, there was a fairly significant decrease for the most recent pricing period with prices dropping 17 percent.

Q. ARE OBJECTIONS ALSO RAISED BY OSBA REGARDING YOUR PROPOSED CHANGES FOR THE SMALL C&I CUSTOMERS?

A. Yes. Mr. Kalcic opposes my recommendation to replace a portion of the proposed 12-month supply contracts for this class with 6-month and 3-month contracts. Mr. Kalcic states that Act 129 does not support RESA's view that default service should reflect "prevailing market prices" and concludes that RESA's proposal would subject small C&I customers to excessive price volatility because 50% of the supply would be procured via 3-month contracts. (OSBA Statement No. 2 at 3).

Q. HOW DO YOU RESPOND TO OSBA'S CONCERNS?

A. I disagree with Mr. Kalcic. First, I have already discussed issues relating to price stability above and in prior testimony in this proceeding, and I disagree with OSBA that RESA's recommended portfolio would result in excessive price volatility. Second, the Commission has expressed a clear preference towards default service rates that reflect underlying market prices, and it did so when considering the current Act 129 standards. While the Commission in the *End State Order* determined that legislative changes might be necessary for the exclusive use of quarterly contracts for residential and small C&I contracts, the Commission specifically held that, in the absence of legislative changes, "we will consider an alternative shorter-term product that is more reflective of market conditions than the currently-offered default service products."[5] I am not proposing the exclusive use of quarterly procurement contracts for these classes of customers. RESA's proposal for residential and small C&I procurements is comprised in part of shorter-term products than those proposed by Duquesne and OSBA and is well within the confines of the *End State Order*.

B. Medium C&I customers over 100 kW have interval meters and should receive hourly default service.

Q. OSBA DESIRES TO CONTINUE THE 6-MONTH PROCUREMENT CONTRACTS CURRENTLY IN EFFECT FOR MEDIUM C&I CUSTOMERS, AND DUQUESNE TESTIFIES THAT IT IS NOT OPPOSED TO THAT VIEW

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[5] *End State Order* at 41.

EVEN THOUGH ITS PLAN INCLUDES QUARTERLY PROCUREMENT CONTRACTS FOR THESE CUSTOMERS. HOW DO YOU RESPOND TO THESE PROPOSALS?

A. As I stated in earlier testimony, all of Duquesne's 100 kW to 300 kW medium C&I customers have interval meters and can be transitioned to hourly service consistent with the Commission's *End State Order*.[6] (Customers between 25 kW and 100 kW would receive default service supplied through quarterly contracts as proposed by Duquesne.) To the extent that Duquesne can show that its internal systems are not capable of immediately transitioning the 100kW to 300 kW customers to hourly default service, RESA recommends that the Commission mandate a transition schedule that would require hourly default service be phased in by customer size over the duration of the plan period, and that Duquesne procure default service load using quarterly contracts in the interim.

C. <u>Large C&I hourly default service should be bid out</u>.

Q. DUQUESNE OPPOSES RESA'S POSITION THAT HOURLY DEFAULT SERVICE SHOULD BE BID OUT. (DUQUESNE STATEMENT NOS. R-3 AT 42 AND R-4 AT 18). HOW DO YOU RESPOND?

A. RESA's position on this issue is consistent with the Commission's policy position as stated on page 30 of the *End State Order*:

> As to the Industrials' proposal that hourly-priced services for large C&I customers be provided by the EDCs, the Commission prefers the model under which these services are auctioned to wholesale suppliers. Having the EDC providing these services and charging an administrative adder to large C&I customers entails a degree of involvement by the EDC that the Commission seeks to avoid with this group of customers in the robust competitive market we are seeking to promote.

Moreover, Duquesne's argument that it should continue providing hourly default service because it "has one of the best retail access programs in the country for Large

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[6] *End State Order* at 29, 31.

C&I customers in terms of switching and only a small portion of load remains on default service," (Duquesne Statement No. R-3 at 42), even if true, is beside the point. Regardless of how successful the program or how significant the load, RESA's view is that competitive forces should provide the service, and that doing so is consistent with Act 129 and will not impose significant costs upon customers because the product will be obtained via competitive bid to the lowest bidder.

III. <u>DEFAULT SERVICE RELATED COSTS</u>

Q. PLEASE DESCRIBE MR. PFROMMER'S RESPONSE TO YOUR RECOMMENDATION THAT DUQUESNE IDENTIFY AND ALLOCATE ADDITIONAL DEFAULT SERVICE RELATED COSTS TO DEFAULT SERVICE RATES.

A. Mr. Pfrommer opposes my recommendation, citing several reasons:

(i) He argues that RESA has made these arguments in the past and that the Commission has not ordered a full scale unbundling as a matter of policy;

(ii) He notes the negotiated POR settlement from 2006 where parties agreed to the implementation of POR in lieu of further cost unbundling;

(iii) He argues that additional unbundling would likely have only a minimal effect on the PTC; and

(iv) He argues that all customers should pay for default service related costs because default service is a standby service that all customers benefit from.

Q. ARE YOU ADVOCATING FOR A FULL SCALE UNBUNDLING IN THIS PROCEEDING?

A. No. Mr. Pfrommer is correct that RESA has previously advocated for a full scale unbundling of all default service related costs, including billing and customer care costs, to reallocate such costs to default service rates. While RESA believes that this would be appropriate and this is supported by the Commission’s default service policies, I am not advocating for a full scale unbundling in this proceeding. Rather, I believe Duquesne should, at a minimum, allocate to default service rates certain specific costs that are directly related to the provision of default service. This would include all costs associated with developing and administering the default service plan (such as litigation and consultant costs, in addition to costs associated with running the competitive solicitations), cash working capital utilized in the provision of default service, billing system and information technology costs associated with implementing the default service plan, and any bill inserts or customer communications related to the default service plan. A full scale unbundling would also review joint and common costs, and indirect costs. This would include an attempt to allocate a portion of the entire customer care and billing system costs to default service rates in recognition of the fact that such systems are used for both default service and distribution service functions. Although I am not advocating for this type of full scale unbundling, the direct default service related cost should be identified and allocated to default service rates.

Q. PROVIDE AN EXAMPLE DISTINGUISHING YOUR PROPOSAL FROM WHAT WOULD OCCUR UNDER A MORE COMPREHENSIVE UNBUNDLING REVIEW.

A. Billing and IT systems are a good example. Under a full scale unbundling one would look at Duquesne’s entire billing and IT infrastructure and identify a way to allocate all of the costs for these functions between distribution service and default service because the billing system and supporting IT systems are used in the provision of both services. For example, one metric that could be used would be to develop a cost allocation factor that would split these costs on the basis of revenue with a large portion reallocated to default service because a large portion of Duquesne's revenue is from default service sales. This would likely be a contentious issue because Duquesne would undoubtedly argue that it is not appropriate to allocate such costs on the basis of revenue. An alternative approach would be to only allocate certain clearly identifiable costs that can directly be tied to the default service function. For example, if Duquesne were to incur incremental IT and billing system development costs to implement hourly priced default service for Medium C&I customers, this would be a direct cost that should be allocated to default service rates. Another example would be customer notification costs. Under a full scale unbundling all cost of communications would be split between default service and distribution rates. Under the approach that I am advocating for in this proceeding, Duquesne would identify the specific default service related customer notifications (for example notifications about an upcoming PTC change or notices about customers being reassigned to a different procurement group) and assign these to default service rates.

Q. MR. PFROMMER ARGUES THAT THE IMPACT TO THE PTC WOULD BE SMALL. DO YOU AGREE THAT THIS IS A VALID REASON FOR NOT FOLLOWING PROPER COST ALLOCATION PRACTICES?

A. No. The Commission has stated in its Default Service Policy Statements that these types of costs should be allocated to default service rates (see below excerpt). Whether the resulting impact to the PTC is significant or not, Duquesne should follow the Commission's cost allocation policies.

<u>§ 69.1808. Default service cost elements.</u>

(a) The PTC should be designed to recover all generation, transmission and other related costs of default service. These cost elements include:

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> (4) Administrative costs, including billing, collection, education, regulatory, litigation, tariff filings, working capital, information system and associated administrative and general expenses related to default service.

Q. PLEASE RESPOND TO MR. PFROMMER'S REFERENCE TO THE 2006 SETTLEMENT AGREEMENT.

A. Mr. Pfrommer cites a 2006 settlement agreement in which Duquesne and other parties, including RESA, agreed to the basic parameters of a POR program. Although the POR program was initially negotiated as an alternative to full scale unbundling of default service related costs, this in no way precludes RESA from advocating for further cost unbundling in this proceeding, or the Commission from directing that such unbundling occur. The express terms of the settlement provided only that Duquesne would not be required to further unbundle its distribution rates prior to December 31, 2010. It is now more than 3 years later.

IV. <u>STANDARD OFFER PROGRAM</u>

Q. HOW DOES MR. PFROMMER RESPOND TO YOUR CONCERNS REGARDING DUQUESNE'S PROPOSAL TO UTILIZE THE POR DISCOUNT RATE TO PAY FOR ENHANCEMENTS TO THE SOP?

A. In my direct testimony, I objected to Duquesne's proposal to utilize the POR program discount rate to pay for the costs of the proposed SOP enhancements. Among other reasons, I explained that using the discount rate would place a disproportionate level of costs on customers with larger volumes of usage. Mr. Pfrommer objects to the example in my direct testimony that illustrated this inequity by calculating the impact to a typical medium C&I customer. Mr. Pfrommer argues that the example is inappropriate because "there would be no Medium C&I SOP charges under the POR because the Medium C&I customers do not participate in the SOP." (Duquesne Statement 4-R at 8).

Q. DOES THE CLARIFICATION THAT NO COSTS WOULD BE ADDED TO THE MEDIUM C&I POR RATE ELIMINATE YOUR CONCERNS WITH THIS COST RECOVERY APPROACH?

A. No. While I am pleased that Duquesne has clarified that it would not increase the medium C&I POR discount rate to pay for the SOP program enhancements because these customers are not eligible for the program, this clarification does not eliminate the concerns. I continue to believe that the POR discount rate is a wholly inappropriate cost recovery mechanism for the SOP. Mr. Pfrommer takes issue with the example presented in my direct testimony because a medium C&I customer would not face the incremental POR discount rate. However, the point of the example still holds true. If the analysis is updated to compare the cost for a residential customer to the cost for a small C&I customer, who would be eligible for the program, it still shows that the small C&I customer pays significantly more (nearly 13 times more) than the typical residential customer.

Increase in POR discount rate to pay for SOP: 0.1% incremental discount rate above current level. For illustrative purposes only.	
Cost to a typical residential customer	**Cost to a small commercial customer** **(24kW @ 55% load factor)**
Average monthly usage: 750 kWh	Average monthly usage: 9,636 kWh
EGS Price $0.07/kWh	EGS Price: $0.07/kWh
Average monthly bill: $52.50	Average monthly bill: $674.52
Cost of POR discount rate for SOP: $0.0525	Cost of POR discount rate for SOP: $0.67

Q. MR. PFROMMER ALSO ARGUES THAT COST PER KWH UNDER DUQUESNE'S PROPOSED POR DISCOUNT RATE METHODOLOGY WOULD BE MINIMAL. DOES THIS JUSTIFY THE PROPOSAL?

A. No. Mr Pfrommer provides a sample calculation that shows the per kWh impact as $0.00013. First, I would note that this is based on a hypothetical cost estimate. Duquesne has not presented specific cost details and it has not committed to cap the increased costs at a certain level. So it is not even possible to evaluate the impact to customers or EGSs under Duquesne's proposal. This is why I believe it is premature to approve a revised cost recovery methodology at this time. However, even if you assume for the sake of discussion that the cost estimates presented in Mr. Pfrommer's testimony are final, this does not alleviate my concerns with using the POR mechanism. Although the per kWh cost to a typical residential customer would be small, this translates into significant amounts for the EGS whose accounts receivables are discounted by the POR discount rate. For example, an EGS serving 50,000 residential customers who they acquired individually outside of the SOP would pay approximately an additional $58,500 using Mr. Pfrommer's $0.00013 per kWh number (assuming an average 750 kWhs per month), even though the EGS is not participating in or benefitting from the program.

Q. DO YOU AGREE THAT THE COMMISSION'S APPROVAL OF A POR COST RECOVERY MECHNAISM FOR SOP COSTS IN THE PECO PROCEEDING IS JUSTIFICATION FOR DUQUESNE'S PROPOSAL?

A. No. Mr. Pfrommer notes that the Commission has approved using the POR discount rate for SOP costs for PECO. While this is true, there appears to be a difference between what PECO is doing and what Duquesne has proposed. PECO had a discount rate of 0.2% for its POR program. This was intended to pay for implementation and administrative costs for the POR program. This discount rate was scheduled to expire once all such costs were recovered. PECO proposed continuing this 0.2% discount rate in order to pay for SOP related costs. Accordingly, the proposal for PECO was to continue an existing discount rate mechanism at the already approved level. It appears that Duquesne is proposing to increase its POR discount rate to pay for the SOP. While RESA is opposed to utilizing the POR discount rate for SOP costs in either instance, this is an important distinction. I continue to believe it is premature to adopt a revised cost recovery plan until all of the SOP details are resolved.

Q. HOW DO YOU RESPOND TO DUQUESNE WITNESS MICHELE R. SANDOE'S TESTIMONY REGARDING THE ISSUE OF THE STAKEHOLDER PROCESS TO DISCUSS THE SOP?

A. Duquesne witness Ms. Sandoe states that Duquesne expresses concerns about a Duquesne-specific collaborative and suggests that the Commission consider a statewide collaborative process. (Duquesne Statement No. R-5 at 15.) I am not necessarily opposed to addressing the SOP issues through a statewide collaborative forum. However, I am concerned that a statewide process might not afford the participants ample opportunity to digest Duquesne-specific information, including information leading to decisions about whether it is reasonable to hire a third-party administrator, scripting issues, and so forth. For the collaborative process to be successful, Duquesne will need to present parties with updated and detailed information about its program. Parties will then need an opportunity to review the information and offer feedback. This would involve numerous issues and would most likely require more than one meeting. While I agree that the stakeholders can learn from assessing each of the EDC referral programs, I would not want to jeopardize a detailed process for reviewing the efficiency and effectiveness of Duquesne's program.

V. NON-MARKET BASED CHARGES

Q. PLEASE DESCRIBE DUQUESNE'S AND OCA'S TESTIMONY REGARDING NON-MARKET BASED CHARGES.

A. Duquesne witness Mr. Pfrommer and OCA witness Mr. Estomin submit testimony opposing my recommendation to shift certain non-market based charges to Duquesne which would assume these costs for all load. Mr. Estomin states that the Commission recently rejected RESA's proposal in the FirstEnergy default service proceeding[7] and also that there is no evidence to suggest that NITS charges are sufficiently volatile and unpredictable to warrant treatment as an EDC non-bypassable rate element. (OCA Statement No. 1R at 6). Mr. Pfrommer contends that RESA's recommendation should be rejected for several reasons, including that: (1) some customers may have contracts in place that extend into the next plan period beginning June 1, 2015; (2) RESA's reliance on the Commission's November 14, 2013 order regarding fixed versus variable pricing as support for making transmission charges nonbypassable is misplaced; and (3) collecting through non-bypassable charges will result in unbundled transmission rates and contradict the design of customer choice, alter the PTC thereby creating customer confusion, and limit the breadth of options to customers available in the competitive market. (Duquesne Statement No. R-5 at 19-224).

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[7] *Joint Petition of Metropolitan Edison Company, Pennsylvania Electric Company, Pennsylvania Power Company and West Penn Power Company for Approval of their Default Service Programs*, Docket Nos. P-2013-2391368, P-2013-2391372, P-2013-2391375, P-2013-2391378, (Opinion and Order entered on July 24, 2014).

Q. DO YOU AGREE THAT THE COMMISSION'S DECISION IN THE FIRSTENERGY CASE PROVIDES A SUFFICIENT REASON TO REJECT RESA'S PROPOSAL REGARDING NON-MARKET BASED CHARGES?

A. No. To the contrary, the outcome in the FirstEnergy proceeding supports RESA's position on several of these non-market based charges, as more fully discussed below. The outcome in the FirstEnergy case is that most of the charges at issue will be treated as non-market based charges for FirstEnergy's DSP III period (including TEC, ECR, Generation Deactivation, Unaccounted for Energy, historic out of market tie line and retail meter adjustments). The only charge that will not be treated as a non-market based charge is NITS.

Q. PLEASE COMPARE THE OUTCOME IN FIRSTENERGY'S DSP CASE TO WHAT DUQUESNE IS PROPOSING FOR ITS DSP IV.

A. Prior to its DSP III proceeding, FirstEnergy had already assumed responsibility for two PJM charges as non-market based charges on behalf of all load. These are Expansion Cost Recovery and Transmission Enhancement Charges. In the recently approved settlement in that case, additional charges will also be treated as non-market based charges and recovered through non-bypassable rates. These new items include: (i) Generation Deactivation charges for which charges are set after the date of the Order approving the settlement, (ii) Unaccounted for Energy, and (iii) historic out of market tie line and retail meter adjustments. For Duquesne, currently none of these items are assumed by the EDC on behalf of all load. However, Duquesne does assume some of these items for its wholesale default service suppliers. As can be seen in Duquesne's response to RESA 1-16, which was attached as Exhibit RJH-2 to my direct testimony, Duquesne assumes the following cost obligations for wholesale default service suppliers only, and not for EGSs: (i) NITS, (ii) Transmission Expansion (RTEP), and (iii) Generation Deactivation Charges.

Q. WHAT WOULD NEED TO CHANGE IN ORDER FOR DUQUESNE'S DSP IV OUTCOME TO BE CONSISTENT WITH THE OUTCOME IN THE FIRSTENERGY PROCEEDING?

A. Duquesne would need to modify its plan in order to assume several non-market based charges on behalf of all load, including load served by EGSs. The costs would be recovered through a non-bypassable charge. The charts attached as RESA Exhibit RJH-9 compare the outcome in the FirstEnergy case to Duquesne's current structure and RESA's recommendation in light of the outcome in the FirstEnergy case.

Q. IN LIGHT OF THE OUTCOME IN THE FIRSTENERGY CASE, DOES RESA CONTINUE TO SUPPORT TREATING NITS AS A NON-MARKET BASED CHARGE THAT WOULD BE COVERED BY DUQUESNE FOR ALL LOAD?

A. Yes. I recognize that the Commission rejected RESA's proposal in the FirstEnergy case to treat NITS as a non-market based charge. However, there is one very important difference between the FirstEnergy case and Duquesne. As noted above, Duquesne currently already assumes NITS on behalf of its wholesale default service suppliers. This was not the case in the FirstEnergy DSP III proceeding because the FirstEnergy EDCs did not assume NITS for wholesale suppliers. If the Commission were to adopt the same outcome for Duquesne (rejecting NITS as a non-market based charge), this would continue a competitive disadvantage between EGSs and Duquesne's default service. This is explained in more detail in my direct testimony. This difference warrants a different outcome regarding NITS for this proceeding.

Q. DO YOU HAVE AN ALTERNATIVE RECOMMENDATION IF THE COMMISSION DECIDES NOT TO TREAT THESE VARIOUS CHARGES AS A NON-MARKET BASED CHARGE?

A. Yes. If the Commission does not adopt my recommendation for Duquesne to assume cost responsibility on behalf of all load, including EGS load, then the Commission should direct Duquesne to modify its wholesale supplier SMA to require default service suppliers to also assume cost responsibility for the same charges that EGSs are responsible for. I do not believe this is the ideal outcome because this will require wholesale suppliers to account for the risk of these non-market based cost items in their bid prices which may drive up risk premiums and resultant default service rates. However, if my preferred recommendation is not adopted, this is the only way to ensure parity between EGSs and default service, eliminate discriminatory treatment and permit access to Duquesne's distribution system on an equivalent basis.

Q. MR. ESTOMIN STATES THAT NITS CHARGES HAVE NOT BEEN SHOWN TO BE SUFFICIENTLY VOLATILE AND UNPREDICTABLE TO WARRANT TREATMENT AS AN EDC NON-BYPASSABLE RATE ELEMENT. HOW DO YOU RESPOND?

A. In my direct testimony, and above, I discuss how Duquesne's current approach does not result in a level playing field for these cost components. This is because Duquesne's current approach passes these costs through at their current level (subject to any after-the-fact reconciliation adjustments). As such, the price for these items does not reflect the risk that such components can and do change. By comparison, EGSs must embed risk premiums to account for this risk. Mr. Estomin implies that the record in this case does not support RESA's view that these costs are not volatile enough to warrant becoming non-bypassable charges. (OCA Statement No. 1R at 6). However, these costs can be significant. For example, PJM has information on its website that lists the historical transmission upgrades approved under the RTEP process for each transmission zone and the associated cost allocation to each zone.

The total for these historical transmission upgrades is about $26 billion across the entire PJM system with about $474 million allocated for the Duquesne zone.[8] Additionally, the chart below shows the range of NITS increases for various PJM utilities for the new NITS rates that went into effect June 1, 2014. This shows changes to the NITS rate for about half of the applicable zones, including Duquesne. Although the rate change for the Duquesne zone was only 9% for this recent change, there are more significant increases for other transmission zones. The rate changes for June 2014 vary from a decrease of 15 percent to an increase of 29 percent. As another example, the NITS rate in effect for the PPL zone for January 1, 2013 was $24,119/MW-Yr and this increased to $36,668/MW-Yr for June 1, 2013, a 52% increase.[9] This demonstrates the potential volatility in transmission costs.

8 Source: http://www.pjm.com/planning/rtep-upgrades-status/cost-allocation-view.aspx

9 Source: http://www.pjm.com/markets-and-operations/market-settlements/network-integration.aspx

Zone	% Change	Old Rate ($/MW-Yr)	New Rate	Diff
AP	0%	17,895	$17,895	-
APPA	0%	17,895	$17,895	-
BGE	12%	22,369	$25,047	2,678.00
CNTIVNJ	12%	28,526	$32,049	3,523.00
COMED	11%	21,732	$24,025	2,293.00
DMVDE	29%	23,938	$30,793	6,855.00
DMVMD	29%	23,938	$30,793	6,855.00
JC01	0%	15,112	$15,112	-
METED	0%	15,112	$15,112	-
PECO	0%	20,942	$20,942	-
PENELEC	0%	15,112	$15,112	-
PEPCODC	7%	23,265	$24,949	1,684.00
PEPCOMD	7%	23,265	$24,949	1,684.00
PPL	6%	36,688	$38,729	2,041.00
PSEG	0%	70,697	$70,697	-
DUQ	9%	35,781	$39,053	3,272.00
RECO	0%	32,114	$32,114	-
PENN	-15%	15,087	$12,769	(2,317.92)
CSP	0%	32,035	$32,035	(0.25)
OPCO	0%	32,035	$32,035	(0.25)

Q. DO YOU AGREE WITH MR. PFROMMER THAT IF THESE COSTS WERE SHIFTED, CUSTOMERS ON EXISTING EGS CONTRACTS WOULD PAY THESE COSTS TWICE?

A. No. I believe this argument is an overly simplified view of EGS contracting practices. Mr. Pfrommer raises the concern that shifting responsibility for these costs as of June 1, 2015 could negatively impact customers with existing contracts which may include fixed components for transmission related services. Ms. Johnson suggests that if RESA's proposal is adopted, "[c]ustomers locked-in to EGS contracts could be harmed for a significant length of time." (Duquesne Statement No. R-4 at 20). However, EGSs offering a fixed price product are offering a form of risk management that shifts the risk of price changes from the customer to the EGSs. The presumption in the Duquesne witnesses' arguments is that EGS fixed price contracts should be modified if the change in cost responsibility is implemented. This ignores the fact that many other circumstances and assumptions underlying the fixed price may have also changed since the time the contract was first accepted. Customers on fixed products may be better off continuing on the originally agreed-to price, as opposed to reopening and re-pricing the contracts at current market prices. Thus, the "double charging" argument is an overly simplistic view of the issue. However, in an attempt to address this concern RESA is more than willing to consider reasonable transition mechanisms to mitigate this perceived concern.

Q. ARE THERE TRANSITION MECHANISMS TO ADDRESS THE CONCERN OVER EXISTING EGS CONTRACTS?

A. Yes. For example, in the FirstEnergy settlement the change in cost responsibility for Generation Deactivation Charges was limited to only new charges associated with Reliability Must Run unit declarations occurring after the approval of the settlement. Because the change in cost responsibility was limited to new charges there is no concern over "double recovery" for customers' existing EGS contracts. For NITS and other transmission charges, a similar approach could be implemented that fixes the costs at the current level with Duquesne assuming responsibility for any increases. Alternatively, the change in cost responsibility could be deferred to a later date, such as June 2016, to provide a transition period during which many EGS contracts would expire and renew. The new renewal rates offered would reflect removal of the cost obligations from EGSs and address concerns over potential "double recovery." In sum, there are a variety of transition mechanisms that can be considered. If the Commission accepts RESA's proposal regarding non-market based charges, RESA would welcome Commission guidance on this transition issue.

Q. MR. PFROMMER CONTENDS THAT RESA'S RELIANCE ON THE COMMISSION'S NOVEMBER 14, 2013 ORDER REGARDING FIXED VERSUS VARIABLE PRICING AS SUPPORT FOR MAKING TRANSMISSION CHARGES NONBYPASSABLE IS MISPLACED. (DUQUESNE STATEMENT NO. R-4 AT 21-220). HOW DO YOU RESPOND?

A. Mr. Pfrommer contends that the Commission, in its November 14, 2013 order in Docket No. M-2013-236296, provided guidance as to the appropriate use of the "fixed price" label when an EGS presents products with pass-through clauses to potential customers. He describes the order as focusing on "clear communications and disclosure with the customer and disclosure information, not cost recovery as suggested by RESA…." (Duquesne Statement No. 4-R at 22). Mr. Pfrommer misses the point of my reference to this order. I am not contending that the order addressed specific cost recovery of non-market based charges by the EDC. Rather, in my direct testimony, I referenced this order as evidence of the Commission's concern about pass-through clauses in retail contracts, including cost and regulatory change provisions, and fixed and variable rate products. The Commission prohibited EGSs from exercising regulatory change provisions to pass through certain wholesale cost changes, including the cost components at issue in this proceeding, to residential and small business customers who had entered into fixed price contracts. This decision eliminated contracting options available to EGSs to manage the risk of cost changes for these components and effectively requires EGSs to increase the risk premiums in their offers. This, coupled with the fact that Duquesne's price to compare does not include similar risk premiums because the EDC assumes these costs for its wholesale suppliers, creates a clear competitive disparity and unlevel playing field. My testimony was that shifting these transmission-related charges to Duquesne would reduce the likelihood that an EGS would need to trigger a pass-through provision and reduces the risk premiums that are embedded in EGS product offerings. Thus, the

Order issued in Docket M2013-236296 is a clear changed circumstance that warrants reconsideration of the treatment of non-market based charges.

Q. PLEASE ADDRESS MR. PFORMMER'S CONTENTION THAT RESA'S RECOMMENDATION REGARDING NON-MARKET BASED COSTS WOULD CONTRADICT THE DESIGN OF CUSTOMER CHOICE, ALTER THE PTC THEREBY CREATING CUSTOMER CONFUSION, AND LIMIT THE BREADTH OF OPTIONS TO CUSTOMERS AVAILABLE IN THE COMPETITIVE MARKET. (DUQUESNE STATEMENT NO. R-5 AT 19-24).

A. I do not consider these to be valid arguments. First, shifting responsibility for these costs to Duquesne will enhance the competitive market by making it easier for EGSs, who do not have guaranteed cost recovery, to enter the Duquesne service territory and compete with Duquesne, which is the largest retail generation supplier in the territory and which is guaranteed to recover its default service costs. EGSs would be able to reduce the risk premiums in their offers, which benefits customers by allowing EGSs to offer lower pricing. In short, the current structure favors both wholesale default service suppliers and Duquesne to the detriment of EGSs and their customers. Second, while the PTC would need to be adjusted, doing so is no reason to deny RESA's recommendation. The PTC is adjusted at various points in time anyway, so incorporating theses non-market based charges into the PTC should not be problematic.

VI. CONCLUSION

Q. DOES THIS COMPLETE YOUR SURREBUTTAL TESTIMONY?

A. Yes.

RESA EXHIBIT RJH-9

Charge/Pricing Component	**Current Treatment for First Energy EDCs (DSP II)**	**Approved Treatment for First Energy EDCs (DSP III)**	**Duquesne's Proposed Treatment for DSP VII**	**RESA's Recommendations for Duquesne DSP VII (Consistent with outcome in FE DSP III)**
Transmission Enhancement and Expansion Cost Recovery (TEC/ECRC)	Cost Responsibility: EDC assumes for all load. Cost Recovery: All distribution customers through non-bypassable surcharge	Cost Responsibility: EDC assumes for all load. Cost Recovery: All distribution customers through non-bypassable surcharge	Cost Responsibility: Duquesne assumes for wholesale DS suppliers & EGSs assume for their load Cost Recovery: Default and Shopping Customers through retail supply price (PTC or EGS contract)	Cost Responsibility: Duquesne assumes responsibility for all load Cost Recovery: All distribution customers through non-bypassable charge

Charge/Pricing Component	**Current Treatment for First Energy EDCs (DSP II)**	**Approved Treatment for First Energy EDCs (DSP III)**	**Duquesne's Proposed Treatment for DSP VII**	**RESA's Recommendations for Duquesne DSP VII (Consistent with outcome in FE DSP III)**
Generation Deactivation Charges (Reliability Must Run Unit)	Cost Responsibility: Wholesale Suppliers & EGSs are each responsible for their load Cost Recovery: Default and Shopping Customers through retail supply price (PTC or EGS contract).	Cost Responsibility: EDC will assume responsibility for all load for new charges, but EGSs and wholesale suppliers remain responsible for existing charges. Cost Recovery: Will be recovered from all distribution customers through non-bypassable surcharge through for new RMR charges after effective date of Order.	Cost Responsibility: Duquesne assumes for wholesale suppliers & EGSs assume for their load Cost Recovery: Default and Shopping Customers through retail supply price (PTC or EGS contract)	Cost Responsibility: Duquesne assumes responsibility for all load for new charges, but EGSs and wholesale suppliers remain responsible for existing charges Cost Recovery: Will be recovered from all distribution customers through non-bypassable surcharge for new RMR charges after effective date of Order

Charge/ Pricing Component	**Current Treatment for First Energy EDCs (DSP II)**	**Approved Treatment for First Energy EDCs (DSP III)**	**Duquesne's Proposed Treatment for DSP III**	**RESA's Recommendations for Duquesne DSP VII**	
Network Integration Transmission Service (NITS)	<u>Cost Responsibility:</u> Wholesale Suppliers and EGSs are each responsible for their load <u>Cost Recovery:</u> Default and Shopping Customers through retail supply price (PTC or EGS contract)	<u>Cost Responsibility:</u> Wholesale Suppliers & EGSs are each responsible for their load <u>Cost Recovery:</u> Default and Shopping Customers through retail supply price (PTC or EGS contract)	<u>Cost Responsibility:</u> Duquesne assumes for wholesale DS suppliers & EGSs for their load <u>Cost Recovery:</u> Default and Shopping Customers through retail supply price (PTC or EGS contract)	PREFERRED POSITION: <u>Cost Responsibility:</u> Duquesne assumes responsibility for all load. <u>Cost Recovery:</u> All distribution customers through non-bypassable surcharge	ALTERNATIVE POSITION (to be consistent with FE DSP III) <u>Cost Responsibility:</u> Wholesale suppliers and EGSs are each responsible. <u>Cost Recovery:</u> Default and Shopping Customers through retail supply price (PTC or EGS)

Charge/Pricing Component	**Current Treatment for First Energy EDCs (DSP II)**	**Approved Treatment for First Energy EDCs (DSP III)**	**Duquesne's Proposed Treatment for DSP III**	**RESA's Recommendations for Duquesne DSP III (Consistent with outcome in FE DSP III)**
Unaccounted For Energy	<u>Cost Responsibility:</u> Wholesale Suppliers & EGSs are each responsible for their load <u>Cost Recovery:</u> Default and Shopping Customers through retail supply price (PTC or EGS contract)	<u>Cost Responsibility:</u> EDC assumes for all load. <u>Cost Recovery:</u> All distribution customers through non-bypassable surcharge	<u>Cost Responsibility:</u> Wholesale Suppliers & EGSs are each responsible for their load <u>Cost Recovery:</u> Default and Shopping Customers through retail supply price (PTC or EGS contract)	<u>Cost Responsibility:</u> Duquesne assumes responsibility for all load. <u>Cost Recovery:</u> All distribution customers through non-bypassable surcharge

Charge/Pricing Component	Current Treatment for First Energy EDCs (DSP II)	Approved Treatment for First Energy EDCs (DSP III)	Duquesne's Proposed Treatment for DSP III	RESA's Recommendations for PPL DSP III (Consistent with outcome in FE DSP III)
Historic out of market tie-line, generation and retail meter adjustments	Cost Responsibility: Wholesale Suppliers & EGSs are each responsible for their load Cost Recovery: Default and Shopping Customers through retail supply price (PTC or EGS contract)	Cost Responsibility: EDC assumes for all load. Cost Recovery: All distribution customers through non-bypassable surcharge	Cost Responsibility: Wholesale Suppliers & EGSs are each responsible for their load Cost Recovery: Default and Shopping Customers through retail supply price (PTC or EGS contract)	*RESA is not advocating for a change in treatment of these costs for Duquesne. However, RESA would support the following as consistent with FE DSP III: Cost Responsibility: EDC assumes for all load. Cost Recovery: All distribution customers through non-bypassable surcharge