ORDER NO. 81102

In the Matter of the Competitive Selection of Electricity Supplier/Standard Offer or Default Service for Investor-Owned Utility Small Commercial Customers; and for The Potomac Edison Company D/B/A Allegheny Power's, Delmarva Power and Light Company's and Potomac Electric Power Company's Residential Customers.	* * * * * * * * * * *	Case No. 9064

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I. Introduction

On May 10, 2006, the Public Service Commission of Maryland ("Commission") instituted this proceeding to examine Standard Offer Service ("SOS") issues as the State continues the transition to competitive electricity supply markets required by the Electric Customer Choice and Competition Act of 1999 ("1999 Act"). Specifically, the Commission docketed this proceeding as a major policy review covering the provision of SOS to residential and small commercial customers.

Thereafter, in June, 2006, the General Assembly passed Senate Bill 1, now Chapter 5, 2006 Md. Laws, 1st Special Session, ("SB 1"). SB 1 requires the Commission to consider a wide variety of issues associated with SOS and the restructuring of Maryland's electricity industry. Some of those issues, in particular issues pertaining to the provision of SOS for residential and small commercial customers for the rapidly-approaching service year beginning June 1, 2007, are addressed in this case.

The Commission is considering the remaining issues mandated by SB 1, and several other issues, in a companion case, Case No. 9063. There, the Commission is receiving testimony and proposals from parties on a large number of alternative SOS approaches, including all of those specified in SB1. Some of these alternatives represent a significant departure from the competitive procurement methods implemented by this Commission as a result of the enactment of the 1999 Act and employed by this Commission since 2004.

Any significant departure from the competitive electric service framework authorized by the 1999 Act deserves thorough and careful consideration. Many of the new alternatives require long lead times: for example, utility construction and ownership of generation assets cannot be accomplished in a timeframe allowing implementation for SOS beginning June 1, 2007. Accordingly, the Commission has determined that this proceeding will focus on alternatives permitted by the 1999 Act as amended by SB 1 that can be studied and implemented, if appropriate, in time to allow electric companies to acquire the generation needed to provide SOS to their residential and small commercial customers beginning June 1, 2007, in a manner that achieves the best price for customers while also maintaining stable prices.[1]

As noted above, in Case No. 9063 the Commission is considering the alternatives that would be difficult to evaluate and implement in the compressed timeframe available for the upcoming bid period. All parties to this proceeding, albeit to different degrees, recognize the practical necessity of this bifurcation. While time constraints necessitate

[1] Pepco has only one-fourth of its residential SOS already under contract for 2007-2008. BGE has only one-half of its residential load under contract for 2007-2008. This proceeding addresses residential Type I SOS load not already under contract.

the issuance of the Commission's decision in Case No. 9064 prior to its actions in Case No. 9063, all actions pertaining to SOS procurement directed by the 1999 Act as amended by SB 1 will be covered between the two proceedings.

The Commission's notice of procedural schedule for this case directed the parties to address a list of issues relative to SOS procurement for power deliveries beginning in June 2007. Direct testimony was filed on August 28, 2006, by numerous parties and rebuttal testimony was filed September 18, 2006. Hearings were held on September 26 and 27, 2006. Finally, briefs were filed October 10, 2006.

The bulk of SOS contracts will expire in May 2007.[2] Decisions must be made in a relatively short time frame regarding the procurement method to be used to replace these expiring contracts. Those decisions are made in this Order. As described below, this Order carefully balances the General Assembly's overarching objectives set forth in SB 1 of achieving the best price for customers while also maintaining stable prices.

II. <u>Issues and Summary of Parties' Positions</u>

A. SOS Contract Lengths

The Public Service Commission Staff ("Staff") notes that utilities to date have used contracts from one to three years in length to procure SOS. Staff recommends that SOS contracts be limited to one and two-year contracts for the upcoming year's bid process because this will bring all of the utilities into a consistent time period for the end of the contract process and allow future bids to be synchronized. Staff says that three-year contracts have no clear benefit and that its proposal will also give the Commission

[2] The relative proportion of the load expiring in 2007 differs among the utilities.

greater flexibility in implementing changes to future procurements that may be ordered in Case No. 9063 or elsewhere.

Staff criticizes the long-term SOS contract proposals of the utilities in part because it is not possible to determine in advance whether a long-term contract will provide the lowest price over the contract period. Staff points out that holding prices stable for long periods of time may ultimately increase rate volatility and does not encourage competitive markets. Staff says a market-based procurement schedule designed to reduce volatility would use a dollar cost averaging approach over a time period that keeps SOS prices close to market rates, while protecting against price spikes at the time of bids.

Staff says it is not clear how the monthly contract proposal of the Retail Energy Supply Association ("RESA") will be workable due to the number of bidding events that would have to occur each year. Staff says the proposal of Washington Gas Energy Services, Inc. ("WGES") for one-year SOS contracts is a more practical way to conform SOS prices to prevailing market rates using a bidding process similar to the Case No. 8908 process. Staff concludes that SOS is in place to provide basic services, not replacement service; in other words, SOS should be a fall back service. Finally, Staff says it is important for bidders to understand that bids will not be disqualified based upon price, because doing so could adversely affect the procurement process.

The Potomac Edison Company d/b/a Allegheny Power ("AP") recommends SOS contracts of one to three years. AP also says that contracts should be consistent with the PJM Interconnection, LLC ("PJM")[3] planning year, which currently begins June 1.

[3] PJM is a regional transmission organization.

Pepco Holdings, Inc. ("PHI") filed testimony on behalf of its subsidiaries Potomac Electric Power Company (Pepco) and Delmarva Power & Light Company ("Delmarva"). PHI recommends as a transition process that the 2007 bidding cycle include a mixture of one, two and three-year contracts for residential SOS. Type I SOS would be based on one-year contracts. Beginning with the 2008 bidding cycle PHI proposes that small commercial customers and residential customers have SOS bids using rolling three-year contracts.[4] Under this proposal only one-third of a utility's load would be bid out at a time. PHI asserts that because there is price transparency and liquidity for contracts of up to three years, suppliers are less likely to include substantial risk premiums in their bids. Therefore, PHI concludes that the three-year term represents a useful balance of low price and control over volatility that meets the needs for a fixed price SOS and the goals of SB 1. In addition, PHI says its proposal would be another means to get all utilities on the same procurement cycle while allowing a great deal of leeway for the Commission to adjust the procurement process, if necessary, in Case No. 9063. PHI asserts that recent procurements in New Jersey and the District of Columbia support its position because use of the rolling three-year contracts substantially dampened the overall rate increases there. PHI also asserts that volumetric risk provisions for Type I customers can be eliminated because they do not noticeably reduce bid prices.[5]

Washington Gas Energy Services, Inc. recommends that all SOS supply contracts for 2007 bidding not exceed one-year.[6] WGES says such contracts will reflect prevailing market conditions for one-year forward contracts and that suppliers will have sustained

[4] PHI says its contract proposal is premised upon its 100 kW definition of small commercial customers.
[5] The volumetric risk mechanism ("VRM") is discussed in more detail in Section II H.
[6] WGES notes that monthly SOS contracts actually represent the better public policy choice.

opportunities to make competitive offers. WGES asserts that the layering of SOS supply contracts with different contract lengths will as likely produce a higher blended SOS price as a lower blended SOS price from year to year. According to WGES based on experience in the competitive natural gas and electricity markets residential and small commercial customers choose one-year contract terms. WGES says that while shorter-term supply contracts may provide less stable prices, such contracts also enable customers to take advantage of drops in market prices. As an alternative to long-term SOS contracts, WGES supports the rate stabilization options in SB1 as a superior way to deal with price increases. However, if the Commission permits utilities to develop SOS portfolios based upon longer contracts, WGES argues that the utilities should be required to treat SOS as a below-the-line-service, with the risk of loss attendant to such a service. Finally, WGES states that its one-year SOS contract proposal is consistent with the requirements of SB1 at this time because of the limited issues that can be determined in this proceeding.

The Retail Energy Supply Association argues that long-term SOS contracts thwart competition because retail prices will become disconnected from wholesale prices over time. RESA asserts that when wholesale electric prices fall customers could be left with an SOS design that locks in high market prices and no alternatives in a market where competition cannot be sustained. Therefore, RESA proposes that residential and small commercial customer SOS contracts be limited to one month in length. RESA says that monthly priced SOS will also avoid the significant price increases that can occur at the end of long-term SOS contracts. While RESA admits that SOS prices will vary more often under its proposal compared to the current structure, it notes that customers will be able to avoid these monthly fluctuations by choosing competitive offers of a year or longer. Additionally, monthly SOS will not contain the wholesale risk premiums that are in long-term SOS contracts (thereby lowering the SOS price). RESA says that under its proposal the monthly SOS auction price will be blended with the remaining long-term contracts thereby providing a transition portfolio of short, medium and long-term wholesale supply contracts. In the case of residential SOS, the transition will occur gradually over a three-year period to strictly monthly priced SOS, which RESA says, is reasonable. RESA says this gradual transition to competition is consistent with Commission policy. Finally, RESA says that since utilities would continue to recover all SOS related costs, monthly pricing would not place any additional financial risk on utilities.

RESA says the proposals of Staff, AP and PHI will not mitigate the potential for large price increases. However, frequent and small rate changes will promote rate stability. RESA also argues that the one-year contract proposal of WGES will not result in SOS pricing that is responsive enough to changes in wholesale prices because a contract of this length can still become disconnected from market prices for sustained periods.

The Maryland Office of People's Counsel ("OPC") offers three reasons why Staff's proposal to limit bids to one and two-year contracts should be rejected. OPC says committing some portion of the SOS load to three-year contracts for the next solicitation probably will not limit the Commission's options in future procurements. Moreover, OPC says it is not reasonable to arbitrarily limit the terms of full requirement contracts because utilities should maximize price stability and minimize risk by layering contracts of varying terms. OPC also says the Commission can establish the mix of contracts to limit the amount of load committed to years two and three. Finally, OPC, joined by MaryPIRG[7], says the Commission should adopt PHI's proposal to solicit a mix of one, two and three-year contracts for the first round of bidding, but not for later rounds so that procurement alternatives to full requirements contracts that are being considered in Case No. 9063 can be implemented if worthy.

The Maryland Energy Administration ("MEA") opposes RESA's recommendation, arguing monthly priced SOS would not avoid price spikes for customers, but would merely alter the timing. MEA says monthly pricing will create short-term customer exposure to large price fluctuations, and that it will not improve price signals for customers. MEA further states that monthly pricing will simply confuse small customers. MEA says RESA is simply speculating when it claims monthly SOS will produce lower prices because there is virtually no experience with the monthly SOS model. Moreover, MEA asserts that most small customers do not want such a service. Finally, MEA says RESA needs to clarify how its proposal comports with the Commission approved settlements in Case No. 8908, which most retail suppliers accepted.

Baltimore Gas and Electric Company ("BGE") and PHI oppose WGES's proposal to limit SOS contracts to one-year. BGE says the proposal is contrary to the directive of the General Assembly for the Commission to provide customers with price stability. PHI

[7]MaryPIRG is the Maryland Public Interest Research Group.

also says WGES's recommendation is contrary to SB1 and that the General Assembly expects volatility to be controlled through appropriate contract types and lengths. PHI says the inclusion of retail rate increase mitigation provisions is intended as an extraordinary measure, noting its recent credit rating downgrades due to SOS cost deferrals. BGE says WGES appears to want utilities and ratepayers to subsidize suppliers by forcing utilities to borrow hundreds of millions of dollars to "smooth" the volatility that would result from WGES's proposal. Finally, PHI asserts that WGES offers no evidence to support the argument that one-year contracts are what customers want.

PHI argues that Staff's proposal for all utility SOS contracts to end at the same time is not required and could be contrary to the statute. Further, price spikes could be more significant than recent bid rounds. As for RESA's monthly contract proposal, PHI says this completely ignores SB1 goals for price stability. PHI says RESA's references to other states' use of short-term SOS supply contracts fails to account for numerous variables, thus making the comparisons inappropriate. Finally, PHI notes that there are administrative issues and costs associated with the monthly bidding proposal.

Conectiv Energy Supply, Inc. ("CESI") states that monthly SOS contracts will reduce bidder interest and increase the risk premium added to the bid prices. CESI notes that a significant amount of manpower and resources are required to prepare and submit bids. One tranche of SOS load (50 mW) constitutes 1800 mW of power for a three-year bid but only 50 mW for a one-month bid. Further, CESI argues the risk premium with month long contracts will be higher per mW than for longer-term contracts, resulting in higher SOS prices.

On brief, the Mid-Atlantic Aggregation Group Independent Consortium, L.L.C. ("MAAGIC") recommends that the Commission approve quarterly procurements, citing the Commission's recent order instituting quarterly procurements for Type II SOS.[8]

B. SOS Retail Pricing

BGE proposes to alter the format suppliers will use to bid for SOS load for its retail time of use ("TOU") customer classes. BGE will request that suppliers bid time periods consistent with PJM on-peak and off peak periods. In order for BGE to maintain its retail TOU tariff structure, BGE proposes to conduct a market-based transformation of wholesale bid prices into retail tariff prices. BGE says customers will benefit from its TOU rate proposal because they will still retain market-based prices but will also still be guaranteed access to utility-provided TOU rates. BGE asserts that the TOU proposal is consistent with State and federal policy. Moreover, the proposal is similar to the transformation of wholesale bids into retail pricing proposed by AP and approved by the Commission under the Case No. 8908 settlements.

OPC supports BGE's time of use rate proposal for this year's solicitation but recommends that BGE evaluate and report on the impact of its TOU proposal on price offers for TOU load. OPC also recommends that BGE monitor true-up accounts to determine whether more frequent billing true-ups are warranted for its TOU customers.

WGES opposes BGE's proposal. WGES notes the perceived disconnect between market bids that do not respond to time-differentiated specifications for electric supply

[8] MAAGIC is a licensed aggregator for its constituent member trade associations and organizations and their respective individual member companies: Maryland Retailers Association, Restaurant Association of Maryland, Maryland Hotel & Lodging Association, Building Owners and Managers Association of Metropolitan Baltimore, Inc., EPIC Pharmacies, Inc., Printing & Graphics Association – Mid Atlantic, Chesapeake Automotive Business Association, Health Facilities Association of Maryland Service Corporation, and WMDA Service Station & Automotive Repair Association. Approximately 4500 companies are members of the associations and organizations comprising MAAGIC.

and TOU retail SOS sales. WGES says that if wholesale bidders elect to respond with flat bids that the Commission awards as the lowest cost bids, utilities should not have the discretion to "transform" the results into TOU SOS rates. WGES argues that it is up to the utility and Commission to notify customers that TOU products are available in the competitive market place if SOS supply bids are awarded for non-TOU bids. WGES says bidder risk aversion, as suggested in the procurement improvement process ("PIP") Report, is not a sufficient justification to approve BGE's suggested bid transformation calculations. WGES says neither BGE nor the PIP Report explain why bidders were able to submit TOU bids in other circumstances. WGES says that a flat bid response to a time-differentiated request for proposals ("RFP") may indicate a defect in the RFP or award process or some other more generic defect. While BGE asserts that the transformation process is necessary to encourage customer demand response to high energy prices, WGES says such transformed rates would not be the result of competitively bid prices. WGES says this may harm some customers in a class who are not affected by the usage incentives.

WGES notes that winning bidders may benefit from BGE's proposal. Since the winning wholesale supplier(s) will be paid the flat rates they bid, the TOU price signals to retail customers may enable the wholesale supplier(s) to avoid higher cost peak deliveries yet still be paid for higher costs that are not incurred. If flat bids are a concern, WGES says the Commission should investigate and correct the situation. WGES says unilateral transformation calculations confuse customers and are unfair to losing wholesale bidders who may have bid time-differentiated prices,[9] and to retail suppliers who may have time-differentiated products.

C. Definition of Small Commercial Customer and Type I SOS

According to Staff, no one has been able to precisely identify a demand or usage level where a small commercial customer becomes a large customer. Staff has previously recommended that 100 kW be used as the dividing line between small and large commercial customers and continues to consider this as one possible definition because it would be both uniform and simple. However, in this proceeding Staff now proposes that the definition be based on whether a customer has demand metering.

According to Staff, one way to identify a small commercial customer is to see if the customer shares many load characteristics with residential customers.. Since residential customers do not have demand meters, the presence of a demand meter on a commercial account distinguishes larger commercial customers from smaller commercial customers. Staff says use of this definition would benefit the competitive market by creating a simple and consistent demarcation between the smaller mass-market customers and the larger demand responsive customers on the basis of one defining physical characteristic. In other words, Staff recommends that the Commission define small commercial customers as those whose monthly bills are based only on energy usage, even though the utilities have varying criteria for moving customers to demand-metered rate classifications.

In the alternative, Staff recommends a 25 kW limit for the definition of a small commercial customer. Staff notes that defining a small commercial customer even at the

[9] WGES says it does not object to a utility revising bids for TOU periods to conform to PJM time-differentiated products provided customers are made aware of such a service change.

25 kW level would include customers whose demands are on the upper end of the residential size and possible two to four times larger.

Staff asserts that the utilities have grouped small commercial customers based upon their inclination or ability to choose rather than energy usage, which implies many assumptions. Staff avers that by setting the boundary at 100kW, as Staff previously recommended and as currently advocated by several other parties, there is an assumption that customers in that size category lack the sophistication or desire to buy electricity competitively. Staff believes it to be more likely that these factors vary among such customers. Staff says the definition of a small commercial customer should be easy for all customers to understand, especially if they have multiple accounts, meters or service locations. Staff concludes that moving many of what are now Type II customers to Type I service could reduce supplier interest in serving the market, which is not the direction Maryland should take.

According to the Apartment and Office Building Association of Metropolitan Washington ("AOBA") the Commission presently defines small commercial customers for the purpose of SOS as set forth in the Case No. 8908 Settlements as all residential accounts that are not demand metered.[10] AOBA notes that current utility tariffs apply demand metering to BGE customers with a demand of 60 kW or greater and for Pepco customers of 25 kW or greater. AP and Delmarva demand metered customers are

[10] For the record, the Commission has not, prior to this proceeding defined a "small commercial customer." Further, the Case No. 8908 Settlements did not do so, although Type I customers may be limited to accounts that are not demand metered.

between these thresholds. Consequently, AOBA says that while small commercial customers are defined uniformly as non-demand metered non-residential accounts, the definition is not uniform in its treatment of similarly situated customers.

AOBA says a more uniform definition would result in more straightforward, equitable, understandable, ratemaking policies. AOBA recommends that the current Pepco determination of small commercial customers be applied uniformly in the State.[11] AOBA says that advantages of using this definition are: it includes both demand and usage criteria, which can readily be applied to other utilities; it uses the lowest common denominator as a Statewide uniform definition; and the definition can be implemented without additional metering costs or lead times. Furthermore, AOBA believes that it will facilitate customer understanding because the definition is based on readily observable data. AOBA also argues that this definition closely approximates the size of customers that can be found within the residential class.

AOBA states that its recommendation is tied to Commission adoption of "appropriate" ratemaking policies. AOBA believes that commercial customers should be provided rate alternatives that are known far enough in advance so that they can make economic energy procurement decisions, and fixed for long enough periods (at least 12 months) that customers can reasonably understand and evaluate their service alternatives. Otherwise, AOBA would support a much broader definition of small commercial

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[11] AOBA says that the criteria that Pepco presently employs to identify Type I small commercial customers are as follows:

1. The customer must not have a metered 30-minute demand that equals or exceeds 25 kW.
2. The customer must not have energy consumption in excess of 6,000 kWh in any two consecutive winter billing months.
3. The customer must not have monthly energy consumption that exceeds 7,500 kWh for a single summer billing month.

customers, including all current Type I and Type II B commercial customers or, alternatively, those with a peak load contribution ("PLC") of 100 kW or less.

AP emphasizes that customers desire straightforward and easily discernible rules. In order to foster retail competition and customer understanding, AP recommends that the term small commercial customer be based upon the customer's billed distribution rate schedule. AP also says that customers should not be divided on rate schedules based upon parameters such as kilowatt, peak load contribution, or any other such criteria because this would result in unnecessary complexity.

PHI says the use of customer PLC is the most practical means to define small commercial customers and notes that it is already being used to differentiate commercial customers. PHI states that neither rate schedules nor demand meters would provide a uniform Statewide measurement. Further, use of demand meters relies on a technology that may be applied differently in the future thereby making the definition a moving target.[12] PHI concludes that a PLC definition is the most practical approach.

PHI recommends defining a small commercial customer as a customer with a PLC of 100 kW or less.[13] This represents over 97% of PHI's commercial customers but only about 47% of commercial load. PHI asserts that these types of customers do not have the expertise to seek and review offers from retail suppliers nor perhaps even the inclination to shop for electric supply. PHI argues that it would be inappropriate to draw the line at a lower usage level like 25 kW because it would leave so many small businesses without the availability of an enhanced-stability SOS as required by SB1.

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[12] BGE concurs.

[13] According to PHI, existing commitments to Type I SOS suppliers preclude combining all customers below 100 kW in the upcoming procurement cycle; however, as of May 1, 2008, this is not an impediment.

BGE recommends that customers with a PJM capacity of 100 kW or less should be deemed small commercial customers as this definition best fits the idea of "mass market" customers that appears to underlie the small commercial category. Responding to AOBA's proposal, BGE says it would require all electric utilities to reset the threshold between different classes of smaller commercial customers to fit the existing Pepco model. BGE says this model is not necessarily suited to the needs of other utilities' customers. BGE says a uniform definition can be achieved without the collateral impositions of AOBA's proposal. Additionally, BGE says the Commission should not allow SOS to be redesigned, as WGES and RESA advocate, in a way that is unfair to customers who cannot shop.

WGES says that because the restructuring statute included small commercial customers with residential customers as having a greater need for SOS, the Commission should analyze the commercial customer markets to determine which size range has characteristics similar to residential customers. Therefore, the Commission should require the utilities to provide appropriate data for the analysis. WGES argues that information to date implies that only a portion of Type I customers may have similar SOS needs as residential customers. WGES recommends that the Commission identify the subset of Type I customers that have residential characteristics for purposes of developing an accurate definition. As an interim measure, WGES supports the 25 kW cutoff pending completion of the analysis it proposes.

RESA recommends that any non-residential customer with a peak load of 25 kW and below be defined as a small commercial customer. RESA notes that this is the dividing line that Pepco already uses. For customers not having a demand meter, RESA recommends that commercial customers having a maximum usage of less than 9,000 kilowatt hours in each of the preceding 12 months be classified as small. RESA says such customers would currently have annual electric bills over $10,000. RESA notes that parties proposing a 100 kW threshold for defining small commercial customers are essentially requesting expansion of the Type I class. Further, none of the utilities currently use this threshold. RESA says the customer switching statistics demonstrate that customers below the 100 kW range are already making informed buying decisions regarding electricity and should not be classified the same as businesses that exhibit characteristics closer to those of residential customers.

MEA notes that SOS has already been authorized for Type I customers through May 2008 as has Type II SOS.[14] Consequently, defining small commercial customers in this case will have no immediate impact. MEA also notes that the definition is not being considered in the context of a review of electric restructuring, the basic design of SOS or a review of competitive markets. MEA says this issue should be revisited in the future when the Commission conducts industry structure or SOS reviews. However, if the Commission elects to rule on this issue, MEA supports the 100 kW definition on an interim basis. MEA says the right to SOS is an important consumer protection for small customers and given the lack of competitive market analysis it recommends that the Commission err on the side of inclusiveness. Therefore, MEA says the Commission should consider both the customer's level of sophistication in energy markets and competitive conditions. MEA states that customer size serves as a rough proxy for customer sophistication. MEA also asserts that Staff's definition does not clearly address

[14] Order No. 81019 in Case No. 9056 authorizes Type II SOS indefinitely, based upon quarterly bid procurements for the next two years after implementation.

either the need for consumer protection or competitive conditions. Finally, MEA says that the issue of customer class confusion should be addressed in the next procurement improvement process.

MAAGIC also recommends that the Commission use the 25 kW definition for small commercial customers. It can support the use of the existing electricity consumption qualifiers currently used by Pepco for those small commercial customers lacking demand meters. MAAGIC believes that these recommendations appropriately segregate more sophisticated commercial customers from those that more closely resemble residential accounts.

D. 2007 SOS Procurement Bid Schedule

The Staff supports the SOS procurement schedule contained in the Report on the 2006 Procurement Improvement Process ("PIP Report").[15] Staff says that the PIP Report bid week schedule reduces conflicts with other wholesale market activity and minimizes the lag time between when bids are awarded and SOS suppliers deliver the power. AP also supports the bidding timeline in the PIP Report as do BGE and MaryPIRG. WGES states that bids should be solicited and prices for SOS posted in time for customers to have an adequate opportunity to evaluate competing offers. According to WGES, the timeline under the Case No. 8908 process has been adequate. PHI says it has taken account of bidder preferences in devising a bid schedule to encourage bidder participation.

OPC says the bid schedule in the PIP Report represents a reasonable timeline for SOS bids. While it is not practical to delay the first round of bidding to incorporate

[15] The PIP Report was filed in Case No. 8908 and is appended to Staff's testimony as Exhibit PEV-2 in this case.

changes that may result from Case No. 9063, OPC argues that the second and third tranches in 2007 are sufficiently distant in time to allow incorporation of alternative resource strategies for application in those bid tranches. In sum, because the PIP Report's bid schedule permits an opportunity to phase in a portfolio of resource options, OPC recommends its adoption.

E. Bid Week Timing

According to PHI, bidders add premiums to their bids for keeping them open for a period of time. PHI says these risk premiums are the result of three factors: bidding occurs after a weekend; awards are made on the day following receipt of bids; final Commission action may occur as late as the third day after awards. Generally, awards are announced Tuesday afternoon. According to PHI, holding bids open from Monday evening until late in the trading day on Tuesday subjects bidders to volatility risk. Suggested solutions are to change the time for bid closing or making awards sooner. PHI says there are concerns with both approaches and that it would be helpful if wholesale suppliers could quantify the circumstances that would reduce prices the most, if at all. PHI says that it could accommodate changes to reduce the overnight bid hold premium if the Commission does not make changes requiring additional bid analysis. PHI suggests that bids could be accepted by 10:00 a.m. with a conditional acceptance to suppliers by 5:00 p.m. PHI concludes that a mutual commitment to performance is required.

In order to reduce suppliers' bid hold premiums, BGE proposes accelerating the bid due time to 4:30 p.m., one-half hour after the energy markets close, and the awarding of contracts no later than 8:30 p.m. that same day.[16] BGE says the Model RFP could easily be modified to accommodate this change.

CESI says if SOS contracts are awarded on the same day bids are received that it would reduce risks and the size of the risk premium, noting that it is the risk of market fluctuations during the time bids are kept open that causes the need for a risk premium to be added to a supplier's bid.[17] CESI says if morning bids are required, suppliers would like to see bids due on a day other than Monday so that they will have an adequate opportunity to react to weekend market activity. According to CESI, so long as Commission approval is limited to a review of whether the bidding was conducted according to Commission regulations, it would be comfortable executing hedges. However, if the review is less restricted, CESI would have to keep its bids open until completion of Commission review and the risk premium would not be reduced.

WGES also does not oppose proposals to improve the efficiency of bid week procedures; however, WGES says that it is not standard practice in competitive markets for entities soliciting bids to negotiate contracts that guarantee cost recovery of bid premiums. WGES notes that if the Commission determines that a more thorough analysis of bids is necessary that longer hold periods will result in higher bid premiums.

OPC says that the Commission should not modify the current bid week schedule. According to OPC, reducing the time period between bidding and contract award, as proposed by BGE and PHI, is unlikely to significantly reduce price risk premiums and may cause unintended harm to the bidding process.

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[16] BGE's proposal assumes that qualified bids continue to be evaluated solely on price.
[17] CESI is a wholesale electricity supplier.

Staff notes that currently the bid week schedule takes five days, including a two-day period for the Commission to approve or reject bids. This "delay" may increase the risk for suppliers resulting in a price-hold premium. Staff does not object to the concept of reducing the bid week time period, but notes that no party has quantified a price improvement expected from a change in the bid process. AP also supports the bid week timing in the procurement improvement process, but would support improvements designed to bring more competitive bids and lower prices for SOS.

F. Utility Bid Cancellation or Refusal

According to SB 1's newly enacted sections 7-510(c)(4)(ii)(3) and (4), the Commission may alter certain bid parameters to avoid adverse market conditions. This may include authorization for an investor-owned electric utility ("IOU") to refuse to accept some or all of the bids made in a competitive wholesale auction, in accordance with standards adopted by the Commission.

Staff says that in light of the new legislation, the Commission should determine whether or not the bid process was competitive based upon whether the SOS bid prices reflect the lowest bids to fill the required bid blocks. Staff notes that the Model RFP in the Case No. 8908 Phase II Settlement provides for a Price Anomaly Threshold ("PAT") mechanism to evaluate whether bid prices are caused by abnormal market conditions. However, Staff emphasizes that it should be only the Commission, not utilities, that can exercise discretion in rejecting bids. Staff asserts that any action taken by utilities in rejecting bids should be a purely mechanical administration of the Commission's directives, with no discretion on the part of utilities to reject a bid.

AP supports a uniform Commission-approved bidding process. AP says utilities should not have the ability to alter the bidding process or procedures because this would only invite lack of bidder confidence in the process and prudency reviews. BGE also says it would be problematic for utilities to be allowed to refuse to accept otherwise qualifying low bids received in the RFP process, which would likely lead to higher prices. BGE cites the following as potential problems: meeting the market price requirement in the PUC Article; delaying the bid process resulting in higher risk premiums; and fewer suppliers being likely to participate in the bid process. BGE also says that allowing utilities to change bidding dates due to perceived market conditions is unnecessary and dangerous and that utilities should not be in the business of trying to "time the market." BGE concludes that the price-based bid evaluation procedures the Commission has now should not be altered.

PHI recommends that the Commission take action prior to each bid round to affirm that bidding will occur as planned. PHI says the Commission should have a procedure that: assesses the market conditions; affirms or cancels the bidding based on that assessment; explains its decision; and gives utilities direction regarding rescheduling. However, PHI says the Commission should not try to time the market, which poses significant risks. PHI contends that its rolling three-year contract approach eliminates this timing risk. PHI emphasizes that the Commission should not reject bids based upon a subjective evaluation of price because this would cause uncertainty, undermine participation by bidders and lead to a less competitive process. PHI says that if the Commission assesses market conditions prior to conducting bids and allows the bidding to proceed, it should accept the market's response.

WGES says that the practical effect of allowing utilities to accept some bids and reject others would be to re-introduce prudency reviews of utility procurement decisions. WGES asserts that the original restructuring law was designed to eliminate such reviews and rely on competition to discipline electricity sales prices. According to WGES, it is not a level playing field to have a hybrid market where retail suppliers assume the market risks of their decisions, while utilities avoid this risk through guaranteed cost recovery. WGES concludes that if utilities assumed the same risks as suppliers it would not be objectionable to give utilities the flexibility to reject bids and change bid dates.

OPC notes that there appears to be unanimous opposition to the concept of permitting utilities the discretion to reject bids or change the bidding date. OPC emphasizes that such authority should be the Commission's alone. OPC also supports PHI's proposal for the Commission to establish a process prior to each bid round where it would assess market conditions and determine whether to proceed with the upcoming round of bids.

G. Case No. 8908 Procurement Improvement Process Consensus Recommendations

Staff filed the PIP Report as Exhibit PEV-2, and recommends that the Commission approve the items covered therein. OPC notes that the parties agreed to seven modifications to the SOS procurement process, including the following: provision of additional customer data to bidders; allowing bidders to submit credit information electronically; modifying the RFP to clarify when bid assurance collateral will be returned; and conforming the confidentiality provision with the requirements of SB 1. Additionally, the parties agreed to provide suppliers with additional data regarding their load obligations, and to certain modifications to the PAT. Generally, WGES supports the modifications, provided that data made available to SOS suppliers is made available to retail suppliers as well.[18] WGES asserts that modifications to the PAT are unnecessary and inappropriate because of the procurement options SB 1 provides the utilities.

The four utilities (AP, BGE and the PHI utilities) also support the PIP Report recommendations, as do Constellation Energy Commodities Group, Inc. and MEA. BGE notes that the agreed-to SOS procedures represent carefully balanced compromises among a broad and diverse group of stakeholders, which have been tested and fine tuned over three years of operation.

H. Miscellaneous Issues

1. OPC's Alternative Resource Strategies

While not an issue *per se,* as noted above in the summaries of several issues, OPC's presentations in this proceeding are thematically bound by its perceptions of the requirements of SB 1. For example, Witness Alexander's testimony has many observations regarding the appropriateness of prompt implementation of significant changes to the SOS process that she says are authorized by SB 1.

For example, Witness Alexander urges the Commission to consider in this proceeding, among other options, whether the next round of SOS bids should be based upon the "all requirements" contract approach or whether bilateral contracts should be part of the SOS portfolio. Additionally, OPC says the procurement analysis should explore the potential of acquiring "negawatts" through cost effective energy efficiency products and services, new generation or transmission projects, or some combination thereof. OPC says such an approach may result in a lower blended SOS price than

[18] PHI states that it does not object to making aggregated data available to retail suppliers as WGES recommends, provided that incremental costs are recovered.

relying solely on short term all requirements contracts. OPC concludes that SOS should be acquired based on procurement plans submitted by the utilities that reflect exploration of a variety of contract terms, types, and energy management, as well as traditional supply services akin to the days of vertically-integrated electric utility companies. Though less extensive than OPC's presentation, MaryPIRG appears to share OPC's direction.

OPC asserts that other parties ignored the requirements of SB1 or erroneously interpreted these new policies. However, in Witness Wallach's rebuttal testimony, OPC appears to give increased recognition to the practical time constraints that affect the procurement of SOS generation requirements for the year beginning June, 2007. This recognition results in OPC concurring with the positions of the other parties that time constraints make it impractical to incorporate significant changes to the process for solicitation of contracts in the initial tranche of the upcoming procurement cycle. However, OPC further recommends that the Commission incorporate changes found necessary either in this proceeding or in Case No. 9063 in the second and third tranches of the upcoming bid procurement process even if they are dramatically different than current methods.

To facilitate such action, OPC says the utilities should promptly meet with stakeholders to review procurement alternatives. Additionally, a report should be developed regarding recommendations to assure compliance with the "best price" requirement of SB1, with hearings and an order to follow. While OPC acknowledges that certain strategies may not be available for the June 2007, procurement, it believes its recommendations maximize the potential to fulfill the requirements of SB 1 as quickly as possible.

Specifically, OPC asserts that SB1 overturns the Case No. 8908 approach for SOS procurement. Consequently, OPC opposes the recommendations of WGES and RESA for even more frequent SOS procurement. According to OPC, a Maine Public Utility Commission study shows that residential customers prefer price stability, and oppose higher and more volatile prices in order to stimulate competitive markets. OPC asserts that the duty to provide customer choice is now tempered by SB1's mandate to assure the "best price" under a longer term procurement plan that considers alternative resources. OPC says the intent of retail competition was not to foster customer migration at any price, but to use that competitive market tool to offer value and lower prices to consumers. OPC asserts that the proposals of RESA and WGES represent a volatile SOS pricing approach, which is contradicted by the management approach adopted in SB1. Furthermore, almost no state has adopted the approaches recommended by RESA and WGES. OPC says the clear trend is to move away from shorter-term SOS procurement strategies to longer term planning with longer contracts and investments in energy efficiency resources as part of the SOS portfolio. Moreover, OPC disagrees with WGES's proposal to use "rate mitigation plans" to ameliorate reliance upon short-term SOS contracts. OPC concludes that a more direct use of SB1 portfolio management options should be explored.

BGE criticizes OPC for its recommendation to immediately begin a long-term massive overhaul of Maryland's SOS policy with no protections if that overhaul runs into snags, which is likely. BGE says OPC witness Alexander's recommendations are a reckless gamble with customers' welfare. BGE recommends incremental SOS improvements in the wholesale procurement process in this proceeding.

PHI states that the Commission has correctly initiated this case to examine proposals that have a reasonable likelihood of being implemented in the next procurement cycle. PHI says OPC witness Alexander's recommendations are more appropriately addressed in Case No. 9063.

2. Notional Quantity Language in FSA

Constellation Energy Commodities Group, Inc. ("CCG") raises an issue with the language of Section 12.3(b) of the Full Requirements Service Agreement ("FSA"). CCG says the language results in the FSA having a "notional quantity", which results in the FSA being considered a derivative under SFAS 133. Due to accounting rules, the future assignability of the SOS contract is compromised. CCG says this could result in suppliers limiting their participation in the SOS bidding process or including additional risk premiums (thus raising the cost of SOS). To resolve this issue CCG proposes revisions to make the notional quantity language in Section 12.3(b) of the FSA explicitly optional. According to CCG, there does not appear to be any opposition to its proposal, and in fact no party opposed this proposal on brief.

3. Volumetric Risk Mitigation

PHI recommends elimination of the volumetric risk mitigation ("VRM") provisions for future Type I SOS bid awards. PHI says the VRM provisions require extensive administration and do not noticeably reduce bid prices. PHI notes that the VRM provisions have already been eliminated for all other commercial customers and argues that there is no compelling reason to continue them for small commercial customers.

CCG notes that the VRM provisions serve to mitigate the amount of volumetric risk that winning SOS bidders face with respect to changes in the amount of SOS load that the utilities receive and that the bidders are obligated to supply. CCG says suppliers would face significant volumetric risks without the VRM and therefore have to include this risk in prices. Further, CCG argues that migration risks are exacerbated as SOS pricing becomes more frequent, as in the case of the quarterly SOS pricing model, because customers may be more likely to come and go from a product that exhibits volatile pricing. In addition to added risk premiums without a VRM, CCG says bidders may limit their participation in SOS procurements.

MEA opposes elimination of the VRM at this time because PHI's proposal lacks evidentiary support. Moreover, MEA says migration risk concerns may be increasing and this issue warrants more input from wholesale suppliers before making a change. BGE also opposes PHI's proposal. BGE says wholesale bids should be lower because the VRM reduces migration risk, which outweighs the modest administrative burden.

4. Municipal Opt-Out Aggregation

CCG argues that due to the risk of municipal "opt-out" aggregation, suppliers may limit participation in the SOS process or add risk premiums to their bids. CCG proposes new language (in a new section 4.12 of the FSA) to address this issue. The language would permit the seller (suppliers) to recover the costs it incurs as a result of any opt-out aggregation, plus interest, subject to Commission approval. In the alternative, CCG requests that the Commission affirms that any opt-out aggregation changes will only apply to future SOS procurements and not currently contracted SOS load.

OPC says that the Commission should not adopt CCG's municipal opt-out aggregation proposal because it would unreasonably shift aggregation risk from suppliers to consumers. OPC argues that suppliers can most efficiently manage this risk while customers are unlikely to be able to hedge this risk. Finally, OPC says the proposal unfairly exposes consumers to regulatory risk as well. Additionally, Staff opposes this proposal on brief.

PHI also opposes CCG's proposed municipal opt-out aggregation modifications. PHI says CCG seeks a significant change to the FSA for a risk that does not currently exist under Maryland law. PHI says there is also a concern that wholesalers would then have an opportunity to game the system at customer expense.

5. AP's Residential Customers

AP says that SOS procurement for its residential customers should be considered in another case because AP has capped residential generation rates until January 1, 2009. Staff has also suggested in this case that issues pertaining to SOS for AP's residential customers be deferred.

6. Definition of Default Service

WGES proposes that the Commission define "default service" pursuant to amended § 7-510(c)(3)(iii)2 of SB1. According to WGES, the definition for residential and small commercial customers should be as follows: "A back stop service that provides timely market price signals to residential and small commercial customers, that is not hedged by term contracts of longer than one month and does not disrupt or defeat retail electric supply competition." PHI says the WGES proposal to define "default service" is more appropriate for a later case.

III. Commission Analysis and Findings

A. General Discussion

In enacting SB 1, the General Assembly determined that achieving the best price and price stability are primary policy objectives for the design of SOS going forward.[19] These two new explicit components of SOS policy must be harmonized with the overall goals of the 1999 Act to "establish customer choice of electric supply" and "create competitive retail electric supply and electric supply services markets."[20] Accordingly, the role of the Commission is to fashion SOS procurements that simultaneously: 1) advance retail competition and customer choice; 2) achieve the best price for customers receiving SOS; and 3) mitigate against excessive volatility.

The new statute implicitly recognizes that the "best price" and "price stability" goals are competing goals, and will intersect in the appropriate design of an SOS procurement strategy:

> . . . in a manner that is designed to obtain the best price for residential and small commercial customers in light of market conditions at the time of procurement and . . . to protect these customers from excessive price increases . . . . [21]

While the two concepts are not mutually exclusive, they do interact in a converse manner. For example, if the Commission were concerned only with reducing price volatility, we

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[19] SB 1 identified a number of other policy objectives as well. For the purposes of a discussion of the general character of SOS, we conclude that best price and price stability are the *paramount* policy objectives.
[20] Section 7-504
[21] Section 7-510(c)(4)(ii)1.

might order SOS procurements that locked in pricing for several decades into the future and averaged the contract price over the same period. Of course, since such an approach would shift the risk of market fluctuations, the price we might expect under such a proposal might be very high. In addition, for any such procurement to be successful, we would need to lock customers into participating in SOS, thereby depriving them of customer choice. If market prices went down following approval of such a procurement, consumers would be stuck with the higher prices and would not have the opportunity to migrate to competitive suppliers.[22] Nevertheless, despite having high prices and no customer choice, we would have price stability – one of the goals for SOS procurements enunciated in SB1.

At the other end of the policy spectrum, if we were exclusively concerned with achieving the lowest possible price, we might order the purchase of full requirements for the entire load in the day ahead or spot market. Over time, the total cost of spot market energy will be lower priced than the cost of any forward contracting regime. This is because contracts of any extended duration include risk premiums for the transfer of the risk of market fluctuations. Such a spot market strategy might achieve a lower price over time, but the retail price of power could fluctuate 1000% or more on a daily basis.

No party on this record is suggesting either of the above extreme approaches. Instead of placing too much emphasis on either policy goal, we believe the new law calls upon the Commission to balance these objectives. Best price and price stability may be

[22] Ironically, this is precisely what often occurred under the prior regulated model of integrated resource planning.

viewed as the two endpoints of a continuum. The challenge before us in this order is selecting the appropriate point on that continuum for the large majority of residential and small commercial customers that receive SOS, while at the same time encouraging retail competition. Indeed, all of the various proposals before the Commission in this record differ primarily from one another in that they would select different points along the continuum.

Balancing these objectives is not a new idea. Obtaining the best price and price stability were also the primary objectives when the Commission approved the Case No. 8908 framework in 2003. That framework balanced these objectives by selecting a blended portfolio of contracts of one to three years in duration. The contracts were of a reasonable length to ensure reasonably good market-based prices. Moreover, by blending the portfolio of contracts and staggering the termination dates of the various contracts, the Case No. 8908 construct sought to achieve price stability as well.

The misfortune of the 2006 SOS procurements and price increases was due to two events, one of which was a policy failure and one of which was an act of God. The policy failure was insufficient transition planning in the 1999 Act and restructuring settlements approved in 2000 pursuant to the law. Specifically, the law and settlements imposed a long rate freeze followed by the re-pricing of 100% of BGE's load to the market price at a single point in time. The act of God was of course the devastation wrought by Hurricanes Katrina and Rita in 2005 to the energy infrastructure of the United States.

Under the BGE restructuring settlement, on July 1, 2006 BGE went from rates that were 6.5% below 1993 levels to 2006 levels – in one day. This was so because on

June 30, 2006, customers enjoyed frozen rates by virtue of the 1999 Act[23] while the real price of energy had risen dramatically. On July 1, 2006, again by virtue of 1999 Act,[24] rates rose to the market price. The Commission was required then, by law, to shift customers to a "market price" for SOS. These facts, coupled with price increases brought about by catastrophic weather events in the Gulf of Mexico, produced a rate shock to customers that caused overall rates to rise 72% for BGE residential customers.

The problem experienced in 2006 for BGE customers was not a failure of the Case No. 8908 framework for SOS procurement approved by the Commission in 2003, although we endeavor herein to improve upon that effort to make it better for customers. The problem, as discussed above, was the lack of a transition plan following the expiration of unrealistic frozen rates, thereby leaving 100% of residential and small commercial customer load in the BGE service territory exposed to much higher prices.

We are mindful that BGE customers were not alone in experiencing rate shock in 2006. Indeed, both Pepco and Delmarva residential customers saw their SOS rates increase by more than 35%. These customer rates were not frozen below market prices in 2006 as was BGE's residential rates, which is the primary reason the rate increase for PHI's residential customers was not as great. PHI customer prices have been annually adjusted to reflect the then-prevailing market conditions since 2004. Moreover, while approximately 50% of the entire PHI load was being put out for bid last winter at higher post-hurricane prices this was certainly less than the 100% of load being procured for BGE's residential customers. However, when blended with ongoing contracts, it still produced dramatic price increases for PHI's customers.

[23] Section 7-505(d)
[24] Section 7-510(c)(3)(ii)2

Now, with the benefit of substantial experience, the Commission endeavors to modify the procurement policy adopted in Case No. 8908 in order to hone and improve utilities' SOS procurements to better serve customers. The Commission docketed this proceeding and Case No. 9063 to review Maryland's SOS policies going forward. As we have repeatedly noted, Case No. 9063 is the major policy review proceeding for reviewing SOS procurement policy. Case No. 9064 is aimed at making those incremental improvements that can be completed in a timely fashion and within our current statutory framework. In reaching its decision herein, the Commission aims to adopt a procurement policy for investor-owned utilities that can be harmonized with the decisions that are reached in Case No. 9063. We have endeavored to fashion a transition policy herein that does not preordain any decision in Case No. 9063. Nor will our decision herein unduly impair the realization of the final decision in that case by committing to policies that will extend many years into the future. We now turn to a more specific analysis of the components of our consideration in making changes to the Case No. 8908 procurement framework.

B. Conflicting Goals

Price stability, best price - the lowest possible customer bills over extended periods of time, and the obligation to create competitive retail electric markets are three policy objectives that can be difficult to balance and reconcile. As the above discussion highlights, this is precisely the challenge presented whenever we endeavor to make SOS policy decisions. The Commission's task is to strike an appropriate balance between these objectives. There are numerous examples in everyday life and energy regulation where the objectives of stability and low prices conflict, such that price stability does not (or would not) benefit customers. For example, if some price stability mechanism had been in effect for gasoline over the past year, it is unlikely customers would be benefiting from the current drop in gasoline prices, at least to the degree to which it is occurring today. Of course, had a form of price stabilization been in effect prior to the hurricanes of 2005, the increase in prices would likely have been less steep as well. However, had customers not been exposed to higher prices, the demand response and conservation efforts that resulted would not have occurred either. This would have led to excessive consumption, thereby exacerbating our nation's supply crisis and prolonging the recovery.

The imposition of regulatory controls on the pricing of commodities, to the extent it can be done at all, comes at a cost. Among other such costs identified by economists over the years are dampened investment in the regulated industry, higher costs due to the risk that regulators might change the rules of the market or delay recovery of the costs of production, and financial risks in the form of higher costs of capital and the like.

The most obvious electric regulation examples of the potential drawbacks to an over emphasis on price stability (to the exclusion of the best price) are long-term purchased power contracts that were well above market levels[25] and the long-term amortization of construction costs for some nuclear power plants that turned out to be far more costly than expected. Even today, ten years after the Commission fulfilled its legal obligation to approve a long-term fixed-rate contract between AP and AES Warrior Run for AP's purchase of electricity from that Allegany County power plant, AP's customers

[25] Contracts for power from qualifying cogeneration facilities for example.

continue to subsidize that facility to the tune of over $40 million per year. Cumulatively, for 2000-2005 AP's customers have subsidized that plant by more than $260 million**.** Absent that federally-mandated purchase from AES Warrior Run, AP's Maryland customers would have saved that amount and been able to use that money for other purposes.

Maryland's residential SOS experience has produced two different results for price stability in its three years of procurement experience. Overall electric market prices increased following SOS procurements for each of the first two years of SOS. However, due to the structure of the procurement the result was residential SOS prices that were cheaper relative to current market conditions during the 2004-2005 and 2005-2006 Standard Offer Service years.[26] SOS prices have had a "lag effect" when compared to market prices because as prices increased over the last few years, embedded in the portfolio serving customers were longer term contracts approved when prices were lower. The two and three year contracts in the PHI portfolios enhanced the lagging effect of lower SOS prices relative to current market conditions.

However, market conditions thus far for 2006-2007 are the reverse of the first two years. SOS procured early in 2006 is priced above current market conditions – that is, the *current* prices prevalent in today's market are lower than those 11 months ago. If general market prices continue to stay below SOS contracts procured earlier this year, one half of BGE's supply portfolio will reflect above market prices for one more year and one fourth

[26] This example applies only to the two PHI companies because rate freezes were still in effect during this period for BGE and AP residential customers.

of the portfolio will reflect above market prices until June 2009.[27] The BGE experience also demonstrates the impact on residential customers of a significant price change resulting from the procurement of a large part of the portfolio (in BGE's case the entire portfolio[28]) over a relatively short period of time.

In sum, price stability is an important policy objective which must be achieved, but it is accompanied by a substantial risk of locking in above-market prices for long periods of time. Additionally, prices change weekly, daily, even by the minute, resulting in an always-changing array of pricing for spot, short-term and long-term purchases that reflect the market's assessment of current and future risks, opportunities, supplies and infrastructure. In such a dynamic market environment, pursuing price stability may well run counter to the competing objective of attaining the lowest price.

Another primary objective of Maryland's electricity procurement structure is the formation and maintenance of competitive retail supply alternatives. Retail competition can suffer if SOS is priced even slightly below current market conditions for extended periods of time. It can be rightly said that is a risk that competitive suppliers must face if they wish to compete in Maryland's electricity marketplace, but if their perception is that the market is not truly competitive the competitors may choose not to participate at all. Additionally, even when SOS prices rise above market levels, suppliers of customers (in particular residential and small commercial customers who are less familiar with shopping for electricity) may not be prepared to jump back into the Maryland market with a meaningful alternative to SOS.

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[27] Because the PHI companies started their SOS procurement two years earlier, only three-fourths of their portfolios reflect the higher early 2006 prices and those prices will effect only one-fourth of the PHI portfolios in 2007-2008.

[28] This was unavoidable due to the expiration of BGE's power supply arrangements on June 30, 2006.

The Commission's task is to balance the various important objectives set forth in SB 1, the 1999 Act, and the other portions of the PUC Article. Rate stability is an important policy objective, as is achieving the best possible price for customers, and encouraging the development of a vibrant retail market for the benefit of customers. The Commission extends its thanks to the parties for their analysis of these objectives and the help they provided to the Commission in its assessment of the issues.

C. SOS Contract Lengths

The spectrum of proposals from the parties for the term of fixed price SOS procurement contracts ranges from one-month to three-years and more. Viewpoints also differ on whether the SOS portfolio should be made up of contracts with a uniform term, or a mix of different terms. The advocates of contracts with terms longer than one year generally advocate some approach to "laddering" contracts to diversify procurement to avoid procuring the full amount of SOS load in a single year.

As a whole, the various proposals present two different approaches to achieving price stability over time and reducing retail price volatility. One approach seeks stability through longer term contracting, with bids staggered so that at any given time there will be a relatively limited amount of power up for auction. The other seeks to avoid large changes in overall price levels by procuring power more frequently, on the theory that price changes from one month or quarter to the next will not likely be large.

The Commission generally accepts the stability-related arguments in support of laddered contracts. However, the Commission agrees with Staff's conclusion that three-year contracts have no clear benefit over two year contracts, and further limit flexibility for different power supply arrangements that may be found to be appropriate in the future, such as in Case No. 9063. Staff's analogy to "dollar cost averaging", to wit, conducting bids more frequently than on an annual basis, suggests a way to reconcile an appropriate contract term with the benefits of avoiding substantial price corrections as market conditions diverge (either up or down) from the time power was procured under each contract. As described in more detail below, instead of a single annual procurement for SOS, the Commission will adopt two "procurement seasons" per year. We will further incorporate in the procurement a laddering of varying length contracts (required for the transition), not exceeding two years in length. These contracts will expire at different times of the year and in different years, such that if the policy is continued over time, not more than 25% of the SOS load will be procured in a single procurement.[29] Different contract terms will be necessary to transition from the current existing mix of SOS contracts that will still be in place into 2008 and 2009 to the new contracting terms. The Commission notes that a transition will be required from the existing regime to any new SOS construct.

D. SOS Procurement Seasons – Twice Annual Procurements

Three years of SOS contracting have illustrated the problems that can result from limiting the bidding schedule to only one season or having a large share of the portfolio subject to new price levels at one time. The Commission finds that the goal of price stability is enhanced by laddering such that no more than approximately 25% of load is contracted for in any one season. The Commission also finds that contract terms starting

[29] See Attachment 1 for a breakdown of the contract term lengths for each utility in order to achieve the laddering described herein. Attachment 1 provides a graphic representation of the SOS contracting approach required by this Order.

in approximately June and October also allow portfolio related price changes to coincide with the times retail rates normally change between summer and non-summer rates.

The first SOS procurement season will procure SOS contracts starting in June of 2007, and the second "season" each year will procure SOS contracts starting in October.

The combination of varying length contract terms (including a two year contract beginning October, 2007 in Pepco's case) and twice-yearly procurement provides the contract "laddering" advocated in particular by PHI and supported in concept by many other parties,[30] and limits the adjustment to new market price levels to only one-fourth of the total portfolio. As noted above, contract terms starting in June and October also allow portfolio related price changes that coincide with the times retail rates normally change between summer and non-summer rates.

The twice-annual bidding for laddered two-year contracts SOS approach ordered herein should provide smoother adjustments to changing market conditions than the current SOS approach, thus enhancing price stability. Among other changes, it eliminates previous bid cycle timing that sometimes resulted, depending on the year, in 75 or 100 % of contracts being let at the same time, with the resultant potential for dramatic price swings. At the same time, it provides competitive suppliers with two distinct marketing opportunities: providing longer-term (i.e., annual) fixed prices to customers that want such prices; or shorter term contracts for customers who prefer lower prices to the price stability afforded through SOS. On balance, the Commission believes that the SOS approach ordered herein is not harmful to competitive residential and small

[30] This moves the current residential and small commercial procurement process closer to the proposals advocated by OPC and MEA, among others.

commercial retail electric markets, and may in fact provide marketing opportunities at both ends of those markets, while simultaneously providing more SOS price stability.

As to pricing of SOS for residential and small commercial customers under this regime, the record supports the finding that performing twice annual procurements and pricing adjustments will more accurately reflect current market conditions, and be superior to the current model of a single annual procurement and repricing. The Case No. 8908 procurement model set prices for both the summer and non-summer periods once per year. In fact, the pricing for the non-summer period was being set by procurements occurring as much as 11 months prior to the start of the nonsummer period. The regime approved herein maintains twice annual price changes, but refreshes the price through an auction that is conducted closer in time to when the load will be served. This should smooth out rate changes for customers and will minimize pricing volatility.

E. SOS Retail Pricing

BGE's proposal to administratively develop residential TOU rates may be a symptom of a larger problem with the current "priced as bid" approach to SOS in Maryland. The Commission has observed a general trend over the three years of non-residential SOS toward reductions in the difference between on-peak and off-peak TOU rates and reductions in the differential between summer and winter SOS prices. As with the concerns expressed by BGE for residential TOU, it is not clear that these changes in relative non-residential retail prices by TOU and season would be supported by an analysis of wholesale futures, day-ahead or real-time market prices. WGES brought a similar concern to the Commission last year with respect to Type I rates for PHI customers.[31]

The ratemaking standards in the Public Utility Regulatory Policies Act of 1978 ("PURPA") Section 111(d)[32] emphasized that retail electric prices should reflect actual production or market costs as closely as possible in terms of season and time-of-day. The expansion of the PURPA standards in the Energy Policy Act of 2005 ("EPAct05") highlighted a growing concern in the electric industry of a disconnection between the wholesale and retail markets in terms of wholesale costs and retail prices. The Case No. 8908 process was intended to harmonize wholesale and retail markets by allowing the winning SOS suppliers to effectively set retail prices that they believed appropriately reflected the wholesale market in terms of TOU and summer, non-summer averages.[33] This attempt to better link wholesale and retail markets was one of the central principles in the Case No. 8908 "price as bid" approach. It is unfortunate that wholesale SOS suppliers do not appear to be utilizing this opportunity to more accurately communicate market prices to customers.

These pricing trends, and BGE's solution to resolve the problem through administratively developed prices, bring into question the entire approach of asking suppliers to bid the retail rate design. The Commission will address only bid format and TOU pricing for residential and Type I SOS in this Order. The larger issues related to procurement process will be addressed in Case No. 9063.

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[31] See Comments of Washington Gas Energy Services Regarding New SOS Rates, May 25, 2005 in Case No. 8908. In addition to the specific allegations of anomalous rates for Type I customers, the Comments also reveal unexpected rates for some services that were not the focus of the Comments.
[32] 16 U.S.C. § 2621(d).
[33] See Timmerman, Testimony in Support of Settlement Agreement, Case No. 8908, July 18, 2003, at 7.

The Commission is reluctant to alter a process that was specifically intended to harmonize wholesale and retail markets. Resolution of this issue is made more difficult with the absence of testimony by wholesale suppliers[34] and by factors specific to residential TOU that were not fully explored in the record. However, the Commission cannot overlook the PURPA standards requiring TOU rate options for customers.[35] Accordingly, the Commission accepts BGE's proposal to administratively develop appropriate residential TOU rates. BGE shall state in its Bid Plan (and its RFP as appropriate) that it may adjust the Schedule RL TOU rates that result from its winning bids based on a process that shall be described in its Bid Plan. The Commission encourages BGE to calculate some "deadband" for each TOU rating period in each season such that retail prices resulting from the current process that are within the deadband would be unchanged and only prices outside of the deadband would be adjusted.[36] The Commission invites (but does not require) PHI to make similar changes to its Bid Plans for its residential TOU rates. If PHI does so, to the extent it is practical the Commission encourages BGE and PHI to adopt the same approach and guidelines.

[34] The Commission is generally concerned that this proceeding, which is largely about wholesale power supply and the retail pricing of that power supply, has limited record evidence from wholesale power suppliers.

[35] The Commission does not view non-existent or trivial differences by TOU rating period as adequate satisfaction of the PURPA standards if it is clear that there are meaningful time of day or seasonal differences in wholesale market prices.

[36] Of course the process also needs to accommodate the need for estimated revenue resulting from adjusted TOU rates to equal estimated payments to the winning wholesale suppliers based on the prices bid.

F. Definition of Small Commercial Customer and Type I SOS

As was the case with other issues in this proceeding, there was a wide spectrum of proposals for the definition of a small commercial customer, and by implication the definition of customers eligible for Type I SOS. AOBA provides the most convincing presentation that small commercial customers should have characteristics reasonably similar to residential customers and that the current state of customer metering or some customer class legacy is not sufficient basis for the uniformity required by a definition that may apply to a variety of regulatory circumstances. The Pepco customer class based definition recommended by AOBA as the uniform definition for a "small commercial customer" is also attractive because in addition to the 25kW demand criterion, it includes a usage based criterion that would continue to include customers who had relatively low usage but "spiky" demands within the definition. A 25kW criteria was also supported on brief by MAAGIC.

Definitions based on 50kW or even higher demand levels would include customers whose characteristics are likely to be very different from residential customers. An average monthly BGE residential customer bill will be approximately $116 this year ($140 if customers had not had a portion of the bill deferred pursuant to SB 1). A commercial customer using the 25kW definition would have a monthly average bill of $1,200 or more – this amount is roughly equivalent to the annual bill for the average residential customer (the average for small commercial customers between 0-25kW would likely be lower). A commercial customer using 50kW might have a monthly bill of $2400 or more and a 100kW customer would see a $4,800 monthly bill. The Commission finds it difficult to consider commercial customers with <u>monthly</u> bills that significantly exceed annual bills for residential customers to be customers with similar characteristics to residential customers for the purpose of implementing Senate Bill 1. We view a 25 kW demarcation point to be the outer bounds of the General Assembly's directive for defining a small commercial customer, when viewed in the context of bill sizes for residential customers and 25 kW commercial customers.

The Commission adopts the three-part definition advocated by AOBA and referenced above as the definition of small commercial customers for the purpose of defining customers eligible for Type I SOS. Customers who are currently Type I customers under the current Case No. 8908 framework, but who are no longer Type I customers under the new definition, will be eligible only for Type II SOS consistent with the effective date of the new Type I classification.

G. Combination of Residential and Type I SOS

The Commission recognizes that the new Type I SOS definition will make the pool of customers eligible for Type I SOS load smaller for AP, BGE and Delmarva. Because the relatively small size of total Type I load already creates some difficulties for utility Bid Plans, the Commission will accept utility Bid Plans that combine residential and Type I SOS load in the same manner as different customer classes are currently grouped by some utilities under a single SOS type for bidding purposes.[37] This combination will ensure that load blocks are sufficiently large as to be commercially attractive in the wholesale market.

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[37]In all other respects Type I would continue to be a separate service. For example, bid plans would continue to separately solicit prices on a bid sheet for Type I SOS and residential SOS (and residential TOU as applicable).

H. 2007 SOS Procurement Bid Schedule

The approach ordered by the Commission requires two bidding seasons each year rather than the single bidding season in the current approach. The percentage of total load bid during each season will be at most only one-half of the amounts bid under the current approach. This may reduce the need for three bidding tranches plus one reserve tranche in each bidding season.[38] The Commission is also willing to reduce the current 60-day requirement for notice of new SOS prices to 45 days to allow additional flexibility in constructing a bidding schedule for the new approach.[39] Other than the changes and clarifications discussed above, the Commission anticipates that compliance Bid Plans will attempt to avoid conflicts with other major procurements, overlap bid days with the Type II SOS procurements, and otherwise follow the scheduling principles embodied in recent Maryland SOS bidding schedules.

I. Bid Week Timing and Post Bid Public Hearing

The Commission accepts BGE's proposal to close bidding at 4:30 p.m. and award contracts no later than 8:30 p.m. on bid day. This proposal was supported by a number of parties, including one wholesale supplier (CESI), and the limited concerns expressed by parties did not refute the plausible basis for a reduction in "price hold" related risk premiums that could result from this change in the bid day schedule.

[38] For example, the Commission would find two bidding tranches and one reserve tranche in each bidding season acceptable because that would provide a total of four bidding tranches and two reserve tranches each year – an increase of one regular and one reserve tranche with a significant increase in the timing diversity compared to the current approach.

[39] This will also increase the opportunity to separate the bid seasons by as much time as possible.

Bid week schedules shall include a public hearing for the purpose of receiving a briefing to be presented by the Commission's SOS consultant and Staff concerning the conduct of the solicitation and the solicitation results. This hearing shall be held on Thursday of each bid week. The substance will be similar to the briefings provided during the past three years to the Commission by its consultant and Staff. At the hearing, the briefing will include all information that can be made public under the provisions of the RFP and FSA and is normally included in the Staff's public report on the SOS bidding process and results.[40]

J. Utility Bid Cancellation or Refusal

All parties opposed giving utilities some sort of discretionary opportunity to reject bids. Generally the opposition rested on the procedures-based nature of the basic bidding process used in Maryland. Parties strongly stated that utility discretion was inconsistent with that process. Staff clarified that the PAT does provide the utilities with an automatic procedures-based mechanism to reject bids that exceed reasonable prices based on current market conditions. Various parties also clarified that the Commission can reject bids based, for example, on violations of the Commission-approved procurement procedures or an adverse evaluation of market competitiveness.[41]

The Commission agrees with the viewpoints of the parties that utilities should not be provided any discretion to reject bids that otherwise won load under the prescribed

[40] During its bid reviews following each procurement bid, the Commission reviews confidential and highly commercially sensitive bidder specific bid data. The Commission will continue to conduct a confidential *in camera* review of this data.

[41] The Commission also retains the right to cancel a scheduled bid due to extreme circumstances, such as the outbreak of war or natural disaster affecting energy prices.

bidding procedures (including the PAT). The Commission also observes that utility discretion would probably violate the ruling of the Federal Energy Regulatory Commission that strongly supported Maryland's bidding procedures as a shield against the potential for abuse in a utility's relationship with its generation affiliate.[42]

Finally, the Commission has repeatedly noted in this Order that it reads SB1 as requiring consistent treatment for residential and small commercial SOS. Consequently, Type I SOS procurement shall include a PAT mechanism. The utility RFPs shall clarify whether the residential and Type I PATs will be the same, and to what extent they would differ (for example, the Transaction Cost and Risk Adder might differ). Whether the PATs differ may be related to whether Type I procurement is combined with residential procurement.

K. Case No. 8908 Procurement Improvement Process Consensus Recommendations

The Commission approves for implementation the changes included in the PIP Report filed as Staff Exhibit PEV-2. Consistent with WGES's direct testimony regarding the PIP report, information that is specified in the PIP recommendations to be made available to prospective wholesale bidders shall also be available to Maryland licensed retail suppliers.

L. Miscellaneous Issues

1. OPC's Alternative Resource Strategies

The Commission agrees with PHI that issues in OPC's testimony that cannot be sufficiently examined prior to or integrated into the upcoming SOS bid cycle will be appropriately addressed in Case No. 9063. The Commission also notes that an important

[42] See the FERC's July 29, 2004 Order in Docket No. ER04-730-000.

element of the twice-yearly bidding approach proposed in this Order is the increased flexibility it affords the Commission in Case No. 9063 by reducing the amount of legacy power supply that would need to be dealt with in a transition to a significantly different power supply environment. Finally, as previously noted the important decisions regarding the long-term structure of the electric industry require a careful, deliberate approach not possible in the compressed time frame available for the upcoming bid cycle.

2. Notional Quantity Language in FSA

It has always been the intent of the Commission that language in the FSA should provide for the optionality discussed in CCG's "notional quantity" proposal. This broadens the pool of potential bidders. Because one wholesale supplier believes that the current language is still insufficiently clear on this point, the Commission approves the FSA language changes for Section 12.3(b) contained in CCG's filed testimony.

3. Volumetric Risk Mitigation

PHI's objections to the VRM appear to be more related to administration than to the risk mitigation function served by the mechanism within the Maryland approach to SOS. The testimony continues to show wholesale supplier, customer and utility support for the mechanism. The Commission also finds that it provides an important balance to the fact that customers have free month-to-month mobility to move to or from SOS. The volumetric risk mitigation provision serves the public interest well by minimizing the migration risk faced by wholesale SOS suppliers, and thus reducing the risk premiums reflected in their bids. The Commission encourages the parties to review the clarity of VRM presentation in the RFP and FSA and to make certain that the VRM is being administered in a consistent manner by AP, BGE and the PHI companies.

Residential SOS shall implement the same VRM mechanism that will be used for Type I SOS. A VRM mechanism for residential SOS is a reasonable addition to the various provisions that are already intended to achieve the best price SOS as required by SB 1.[43]

4. Municipal Opt-Out Aggregation

CCG has proposed contract language addressing the potential effects of a municipal opt-out program. The Commission will not adopt the proposal at this time but leaves the door open to reconsider this issue if it becomes necessary. The potential for a municipal opt-out program to be enacted is speculative at best. At worst, the CCG proposal, which transfers substantial supplier risk to remaining SOS customers (those not part of the aggregation unit) in the event a municipality elects opt out aggregation, might render such opt out programs unworkable and unattractive. While we decline this proposal, we point out that the residential SOS VRM mechanism being approved in this Order helps to address wholesale supplier risk that could result from municipal "opt-out" aggregation.

5. AP's Residential Customers

The Commission makes no findings in this phase of this proceeding regarding AP's residential SOS. Since AP's rate caps remain in place, and will likely remain so until such time as this Order is superseded by the decision in Case No. 9063, we do not address specific plans for AP residential customers. However, the Commission believes

[43] For example, the existing provisions that select the lowest bids rather than the average bids, the lowest reasonable supplier credit requirements, small bid blocks to encourage supplier diversity, the PAT and diversified bid timing to avoid or reduce the effect of market price spikes.

it to be prudent to avoid an excess amount of AP residential SOS to be contracted during the same season. If nothing changes, 100% of the SOS load will be under contracts that commence January 1, 2009, which was the condition that resulted in the 72% increases for BGE customers. Attachment 1 contains an example for the parties' consideration of how AP could transition to the SOS procurement approach described in this Order by contracting for one-fourth of its residential SOS load in each of two different bid seasons in advance of the final bid season prior to service starting January 1, 2009. In all cases, contract terms would begin on January 1, 2009. Although included for discussion purposes only, we include this illustration herein because such treatment would harmonize AP's procurements with the other Maryland utilities as provided in this Order.

6. Definition of Default Service

The Commission agrees with WGES that the definition of "default service" has significant long-term importance for all Maryland electric customers. However, Case No. 9063 is the appropriate venue for the development of that definition.

M. Case No. 8908 Provisions Not Addressed

All current procurement and other provisions for residential and Type I SOS that have not been addressed in this Order shall remain in effect.

IT IS THEREFORE, this 8th day of November, in the year Two Thousand Six, by the Public Service Commission of Maryland,

ORDERED: (1) The investor owned electric public service companies shall file compliance tariffs by November 30, 2006, for the procurement of Standard Offer Service electric supply for Residential and Type I commercial customers, using two-year contracts, with bidding twice per year, and appropriate transition contracts beginning in 2007 pursuant to the terms of this Order.

(2) An investor-owned electric public service company may file a proposal with the Commission to administratively develop retail time-of use residential Standard Offer Service rates, provided appropriate details are contained in its Bid Plan, and RFP as appropriate.

(3) A small commercial customer is a commercial customer that does not have: a metered 30-minute demand that equals or exceeds 25 kW; energy consumption in excess of 6,000 kWh in any two consecutive winter billing months; or a monthly energy consumption that exceeds 7,500 kWh for a single summer billing month.

(4) The Commission approves the Standard Offer Service procurement schedule (for 2007 procurements) contained in the Report on the 2006 Procurement Improvement Process, subject to any requested and approved modifications necessary to accommodate the twice yearly procurement process described in this Order.

(5) Standard Offer Service Bidding shall conclude by 4:30 p.m. on the bid day and contracts shall be awarded by 8:30 p.m. on bid day, unless the Commission determines that this is not appropriate under the circumstances.

(6) The utilities shall not reject any bids from Standard Offer Service bidders that have won the bid under the Commission's prescribed bidding procedures.

(7) Type I Standard Offer Service shall include a Price Anomaly Threshold mechanism.

(8) The modifications contained in the Report on the 2006 Procurement Improvement Process are approved. Data made available to Standard Offer Service suppliers shall also be made available to retail suppliers on similar terms.

(9) The proposed revisions of Constellation Energy Commodities Group, Inc. to make the notional language in the FSA explicitly optional are approved.

(10) Residential Standard Offer Service shall contain a volumetric risk mitigation mechanism consistent with this Order.

(11) The Standard Offer Service procurement modifications ordered herein shall not apply to Allegheny Power's Residential Standard Offer Service at this time.

(12) All current procurement and other provisions for Residential and Type I Standard Offer Service that have not been addressed in this Order shall remain in effect.

(13) All motions not granted herein are denied.

KENNETH D. SCHISLER
Chairman

ALLEN M. FREIFELD
Commissioner

CHARLES R. BOUTIN
Commissioner

Commissioner Williams abstains from this decision.

Attachment 1 Example of Laddered 2-Year Contracts Bid Twice Yearly with Transition from Existing Contracts

Except for Initial transition period, all contracts are 24 months

Percentages in rows indicate contracts covering entire period, Blank cells following a row indicate ending date

Percentages are of total full service SOS load

Pepco/DPL

Contract Start Dates

Bid Season	Jun-07	Oct-07	Jun-08	Oct-08	Jun-09	Oct-09	Jun-10	Oct-10	
0=Already in place	25%	25%							
1	25%								
1	25%	25%	25%						
1	25%	25%	25%	25%					
2		25%	25%	25%	25%				
3			25%	25%	25%	25%			
4				25%	25%	25%	25%		
5					25%	25%	25%	25%	
6						25%	25%	25%	24 month bid pattern may be continued

BGE

Bid Season	Jun-07	Oct-07	Jun-08	Oct-08	Jun-09	Oct-09	Jun-10	Oct-10	
0=Already in place	25%	25%	25%	25%					
0=Already in place	25%	25%							
1	25%								
1	25%	25%	25%						
2		25%	25%	25%	25%				
3			25%	25%	25%	25%			
4				25%	25%	25%	25%		
5					25%	25%	25%	25%	
6						25%	25%	25%	24 month bid pattern may be continued

AP

Bid Season	Jun-07	Oct-07	Jun-08	Jan-09	Jun-09	Oct-09	Jun-10	Oct-10	
2 (Bid Oct 07 cycle)				25%	(5 mth contract)				
3 (Bid June 08 cycle)				25%	25%	(9 mth contract)			
4 (Bid Oct 08 cycle)				25%	25%	25%	(17 mth contract)		
4 (Bid Oct 08 cycle)				25%	25%	25%	25%	(21 mth contract)	
5					25%	25%	25%	25%	
6						25%	25%	25%	24 month bid pattern may be continued