2009
MARYLAND STANDARD OFFER SERVICE
REQUEST FOR PROPOSALS FOR
FULL REQUIREMENTS WHOLESALE ELECTRIC POWER SUPPLY

QUESTIONS AND ANSWERS

Q1. Who has the Maryland Public Service Commission chosen as a consultant for this procurement process?

A1. The Maryland Public Service Commission has chosen The Liberty Consulting Group.

Q2. Can you please give me more information on the Guaranty process if a bidder is successful in the RFP process?

A2. Please refer to Article 14 of the FSA, and provide a more specific question(s).

Q3. When demand response is implemented, is the Supplier responsible for the unrestricted load that is the load that would have been there if load response was not implemented?
If so, who is responsible for the balancing operating reserves for the deviations between the actual load and the unrestricted load?
Does the historical data provided by the utilities reflect the impact of demand response, i.e. is the data metered load or unrestricted load?

A3. Yes. Supplier is responsible for the full service of the unrestricted load. EDCs are using PJM settlement systems to account for the unrestricted load. ESchedule system is used to settle restricted loads and the eLoadResponse system is used to settle loads not occurring due to restriction (load reduction). See FSA section 4.2 for details.

Supplier/Seller is responsible for load reduction under the settlement rules of the eLoadResponse system which does not include balancing operating reserves. Check PJM eLoadResponse rules.

Please note that the Allegheny kWh data is also unrestricted load; however Allegheny had no load response activity in Maryland during this historical period.

Q4. Regarding Performance Assurance:
Does Aggregate Transactions, for the purposes of calculating the MtM exposure, include transactions from previous solicitations.

Example: If one contract was awarded in the April 2008 procurement and the October 2008, would the MtM calculations look at the April base West

Hub prices and the October base West Hub prices and net the exposures, including the receivables with service beginning in October, or would each be evaluated independently with the possibility of two margin calls.

A4. All transactions for each tranche under the current agreement and all previous agreements are evaluated on a daily basis and netted against each other to determine the counter parties current MtM. Margin calls are then determined off of the aggregate exposure.

Q5 The following is from the 2009 model FSA:

"Monthly Settlement Date" means, with respect to any calendar month of a Delivery Period, the date(s) determined to be the PJM Settlement Date(s) pursuant to the PJM Agreements.

PJM will shift to weekly settlement soon, probably early in 2009. Following implementation of that change, will the Maryland utilities make payments to SOS suppliers weekly also ?

A5. If and when PJM shifts to a weekly settlement, the Maryland utilities will adopt weekly payments to SOS suppliers.

Q6. Can each of the utilities provide PLCs and customer counts for each of the classes within Type 2, broken out by those customers under a 100kW and over 100kW in size?

A6. The EDCs are unable to provide this information respective to each class within Type II. This question is also out of scope of current SOS construct.

Q7. Previously ARR auction results by path have been posted. Will these paths be posted again with any changes?

A7. The ARRs procured in the 2008 annual auction are valid for the whole PJM delivery Year 2008-2009. All Type II contracts auctioned under 2008 RFP will have this ARR portfolio allocated to their load. Similar process will be followed for the 2009 delivery Year under 2009 RFP. First Type II contracts allocated the 2009 ARR portfolio will be auctioned in April 2009 (see utility bid plans).

Q8. RESERVED

Q9. RESERVED

Q10. RESERVED

Q11. Please provide the NSPL (SOS and All Eligible) for BGE, PEPCO, and DPL Residential, Type I and Type II loads.

A11. BGE NSPL data:

10/14/2008 SCALED NSPL		SOS	Eligible
	PL1	267.7	325.0
	PL2	658.2	1,794.7
	Res	3,464.7	3,561.8

PHI and Allegheny have posted Capacity PLCs and NSPL on their websites

Q12. With respect to Article 14.8 Accelerated Payments, if Buyer calls for Accelerated Payment would the then total existing receivable for deliveries made during previous weeks be paid with the first weekly settlement. The total existing receivable at any point in time could be for deliveries during the prior 4 – 7 weeks, depending upon to exact point in the settlement cycle the parties were at.

A12. Accelerated payments under Section 14.8 are for prospective amounts delivered under the FSA only. Previous settlement amounts accrued prior to the request for accelerated payments will be settled in accordance with the terms of the FSA for monthly settlement.

Q13. Similar to the data provided by BGE, can the other utilities provide both the PJM derated load (PJM wholesale load without EHV losses) and retail meter load. In the case of Allegheny, we are provided retail meter load, so can you please provide PJM derated load. In the case of PEPCO and DPL, can you please provide us with load data at the retail meter?

A13. PEPCO and Delmarva MD load data is at the generation zone level with EHV losses. Hourly derate factors can be down loaded from PJM and applied. Load data at the retail meter is unavailable. Suppliers may apply loss factors to Generation Level loads to arrive at the retail meter loads. Allegheny does not have the PJM derated load available by class type.

Q14. Can you please provide an explanation of how the volumes are to be calculated when determining the MtM Exposure under the FSA? Also, if a supplier were to elect §12.3(b) of the agreement to apply there will likely be a disconnect between the volumes used when calculating Buyer's MtM Exposure under the Agreement and the volume used to determine the Settlement Amount upon an Early Termination. Can you please explain why, if a party were to elect the §12.3(b), the volume under the MtM Exposure isn't the historical number which the parties would look to when terminating pursuant to Article 12?"

A14. Contract volumes to determine MtM exposure are provided by the Buyer on the Transaction Confirmation for the applicable Service Type as On-Peak and Off-Peak Estimated MWh Quantity Per 50MW Capacity PLC These monthly MWh are scaled daily using the Base PLC Per Bid Block to account for PLC size of the block at the date of the calculation.

§12.3(b) covers a different situation – early termination – than mark-to-market during performance. The two calculations may correspond, due to common

inputs, but they would not necessarily do so. This is how the contract was written.

Q15. Can the PAT be included in the reserve tranche scheduled for November 10, 2008?

A15. The PAT applies to procurement for all residential and Type I SOS load. Accordingly it will be a part of the November 10 reserve procurement in accordance with the terms of the RFP.

Q16. Were any potential suppliers notified they had won on Monday night, with the initial decision then being reversed by the PUC Friday or was everyone told they were not successful on Monday?

A16. All bids awarded as part of the October 20th solicitation were ordered to be finalized by the Maryland PSC in Order #82279 in Case #9056. No bids that were awarded in accordance with the procedures set forth in the 2009 Request for Proposals and applicable Commission Orders were reversed.

Q17. Will BGE and DPL release additional load data prior to the reserve auction on November 10, 2008?

A17. Yes. BGE has posted final July eSchedule data before Oct 20th tranche. The final August data will not be available until the week after November 10th auction. Delmarva has posted Historical load data through July 2008, and will provide preliminary generation level load data for August thru October based on Day After Sales data on Monday afternoon, November 3.

Q18. The following are questions regarding PSC ORDER NO. 82279 and results of the October 20, 2008 Standard Offer Service (SOS) solicitations. My interpretation of the RFP is that the Commission can take action and not accept winning bids, only if the process is deemed to have been flawed. Action cannot be taken based upon the price of the bids unless pricing exceeds the Price Anomaly Threshold (PAT) in the residential rate class.

In the Order the Bid Monitor testified that the auction was: 1) conducted properly within the Commission's requirements, 2) the utilities followed the necessary procedures, and 3) appropriate security measures were in place. Therefore, the investor owned utilities and Staff recommended that the Commission accept all winning bids.

The Order then states, *"The Bid Monitor further testified that the bids were conducted in the most severe financial crisis in generations and the Bid Monitor concluded that the crisis had a substantial impact on bid prices. Accordingly, a question arose to whether the Commission should take action to disapprove the award of contracts for the bids found acceptable based on the SOS procurement process".* It is clear in the order that market circumstances may have required additional premiums not necessary in past auctions.

Based on 1, 2 and 3 above, what other reason could the Commission base a decision to disapprove the results, and can the Commission disallow the results of the auction based on price in the residential rate class if bid pricing meets the criteria stipulated under the PAT? Please explain.

A18. Based upon the history of SOS service in Maryland, BGE is not aware of any other reason for the Commission to disapprove the results of a procurement. To date, the Commission has not disallowed the results of an auction based upon a price in the residential rate class where the bid pricing has met the criteria stipulated under the PAT. Article I Section 9 of the Phase I Settlement Agreement in Case No. 8908 provides that "Each Utility will submit the final bid results, bid award(s) and proposed contracts(s) to the Commission for its review and determination of compliance with the Utility Bid Plan." The Maryland Utilities cannot speak to the Commission's interpretation of this language.

Q19. For the November 10, 2008 procurement, will any changes be made to the methodology for calculating the PAT given that 11 firms offered 68 tranches in the Oct 20th solicitation?

A19. At this time, there is no intention to change the PAT methodology for the November 10, 2008 procurement. (source: The Liberty Consulting Group)

Q 20. Has BGE or PHI published any information regarding plans for a third procurement process? Is there any information that would allow my company to anticipate future procurements?

A20. The next step may be procurement of residential load during the planned January 12, 2009 auction.
However, the MD PCS has not made the final determination. Next PSC hearing is scheduled for Dec 11th. See the latest document in this case:
http://webapp.psc.state.md.us/Intranet/aboutus/CN%209064%20Notice%20of%20Hearing.pdf
Follow any new developments in case 9064 on MD PSC site:
http://psc.state.md.us

After PSC makes its final determination, affected utilities will post updated auction schedules on their web sites.

Q21. Please provide the capacity PLCs and NSPL (SOS and All Eligible) for BGE, PEPCO, DPL, and APS Residential and Type II loads.

A21. PHI updated capacity PLCs, NSPLs and Customer counts, have been posted on the Pepco and Delmarva RFP Websites, under RFP Data.
Allegheny's updated PLCs and NSPLs will be posted on its Maryland 2008 and 2009 websites on January 7.

Following is BGE's information,

BGE does not have NSPLC on its historical files.
Below is available data:

Sum of scaled	svc		
type	Competition	SOS	Grand Total
PL1	63	235	298
PL2	1,104	597	1,701
PRL	8	300	307
PRX	83	3,095	3,178
Grand Total	2,623	4,306	6,930

Sum of unscaled	svc		
type	Competition	SOS	Grand Total
PL1	64	240	305
PL2	1,130	611	1,741
PRL	8	307	315
PRX	85	3,168	3,253
System Total	2,685	4,408	7,094

Q22. Are there any rate class changes for Pepco, Delmarva or Allegheny Power pending that we should be aware of?

A22. There are no rate class changes pending for Pepco, Delmarva, Allegheny Power, or BGE.

Q23. Does PLC need to be derated since it is measured at the wholesale level?

A23. No, marginal losses apply to energy only not to capacity

Q24. I was wondering what the size of the Maryland auction is April was for BGE, Allegheny, Delmarva, and Pepco. For instance, about how many MWs.

A24. Specific information regarding the April 20 procurement can be found on each of the Maryland utilities' websites. The final bid plans will be prepared and posted week before the auction.

They are not expected to substantially deviate from the MW currently posted. The websites are:

AP	www.alleghenypower.com/rfp
BGE	rfp.bge.com
Delmarva	www.delmarva.com/mdrfp
Pepco	www.pepco.com/mdrfp

Q25. For the April 20th auction, what is the latest date on which finalized historical usage data will be updated by the utilities?

A25. BGE planned to update historical data on Wednesday April 8th. BGE posts only final settlement data so loads will be only through January. Capacity for end of March will be added. BGE also plans to add NSPL data on end of March records and going forward.

PHI is planning to post the January 2009 reconciled hourly load data, and estimated hourly load data for the period February 1st through April 8th on Wednesday, April 8, 2009. Also on that Monday, PHI will be updating the Bid Plans, Historical PLC data, and SOS and Eligible Capacity PLCs, NSPLs, and Customer counts.

Allegheny's historical load data files will be updated on April 13.
The hourly load data will updated to January 2009. Allegheny will also provide updated Bid plans, historical PLC data, SOS and Eligible Capacity PLCs, NSPLs and customer counts.

Q26. Will APS post additional load data to its website? We are seeing that the latest data is as of 9/30/08.

A26. APS will post additional load data through January 2009 on April 13th.

Q27. Can you describe, or direct us to, the parameters and methodology of determining the Price Anomaly Threshold Procedure (PAT) for the April 20, 2009 bid? Regarding the "Cost Elements of Pricing Anomaly Thresholds" (RFP, Appendix 10), can you elaborate on the specific timing for when each cost item is estimated? Can you contemplate a scenario where the existing description, "Prior to each tranche", leaves open the possibility of conducting a PAT using stale prices?

A27. Appendix 10 of the RFP describes the parameters and methodologies to be used in the PAT calculation. No other public information is provided on the methodology. As appropriate, the utility web sites contain supporting parameters

while some supporting parameters are at the PJM site. The specific parameters chosen by the technical consultant for use in the calculation of each cost element and the sources of those parameters are not revealed.

Regarding the timing of the estimates, the latest available data as of the bid date is used for every PAT cost element except the transaction cost and risk adder. The latter is estimated at the start of the annual cycle. Accordingly, the PAT is thought to be using the best data available as of the bid date, which in this case is April 20.

Q28. Can you confirm that the data contained in column SumOfkWh_PJM_Settlement" is measured at the PJM settlement level post marginal loss implementation? If that is the case, please confirm that BGE adjusted their PJM settlement level data from July 1, 2004 - May 31, 2007 to account for this.

A28. BGE has made an adjustment of hourly load data to account for PJM settlement level, derated load levels and BGE premise level volumes (for the period preceding marginal loss implementation at PJM, July 1, 2004 - May 31, 2007). While that adjustment represents the best effort at the time, BGE recommends to rely mainly on the actual data during the period when PJM implemented marginal losses in the settlement (starting June 1, 2007).

Q29. In reference to Q21, are the BGE NSPL numbers for PY9/10? What is the difference between the scaled and unscaled NSPL?

A29. The NSPL numbers are for the calendar year 2009. The 2010 calendar year tickets will be calculated by EDCs in early December 2009. The scaled NSPL posted on the BGE historical data file correspond with NSPL numbers submitted by BGE into PJM's daily market.

The un-scaled numbers are not presented, they would represent raw sum of the NSPL tickets of the customer population. Since that population is changing daily the zone NSPL ticket sum changes daily. It has to be scaled to the annual zonal NSPL kW amount which is settled by PJM in each zone.

Q30. Can you please confirm that the PLCs and NSPLs posted on the bid plans are based on the summer of 2008.

A30. ***Allegheny's*** PLC values are based on the summer of 2007. The PLCs based on summer 2008 will not be effective until June 1, 2009. There are no NSPLs included in the Bid Plan. The NSPL is in a separate file on Allegheny's website, and is based on the summer 2008.

BGE's Bid Plan and Bid Form Spreadsheets are always reflecting current Capacity Peak Load Contribution values. Capacity PLC tickets change annually, every June 1st. The Bid Plan and Bid Form Spreadsheets do not look forward into the contract delivery period. In the Q&A process in April 2009, BGE has

provided Capacity values, which will take effect on June 1, 2009, by Type of Load, customer class, and SOS vs. Shopping.
There are no NSPL numbers in the BGE Bid Plan. BGE provides NSPL values by load type, customer class, and SOS vs. Shopping in the historical data files posted on rfp.BGE.com site. The Capacity and NSPL values on the historical file reflect current values. Individual NSPL values change annually on January 1st. The NSPL values which will take effect on January 1, 2010 will be calculated based on the summer 2009 loads. The calculation is typically performed in December.

PEPCO and Delmarva Bid Plan and Bid Form Spreadsheets reflect current Capacity Peak Load Contribution values for the April 20th solicitation, and are based on the 2007 Summer. There are no NSPLs included in the Bid Plan and Bid Form Spreadsheets.

Q31. The Maryland Re-Regulation Bill (Senate Bill 844), if passed into law, would introduce many risks for SOS suppliers.
How will SOS suppliers' loads be impacted if retail choice is eliminated for residential and small commercial customers?
Will each SOS suppliers' load be automatically increased by its pro-rata share of the load of those customers previously supplied by competitive suppliers, or will supply for these customers be procured separately?
Will SOS be eliminated for residential and small commercial customers?
Will the output of plants built under PSC authority ("regulated plants") be used to directly supply residential and small commercial customers, thus reducing the load of SOS suppliers?
If so, how will this be accomplished? Will tranches of load be carved out of SOS supply to be served by the regulated plants? If so, will the tranches be flat baseload blocks, or load-following slices of system?
Will the output of the regulated plants simply be offered into the PJM markets at cost (this would be the preferred approach).

A31. The legislative session concluded on April 13 and the subject legislation did not pass. In any event, there was nothing in the proposed SB 844 that would have abrogated any past or future SOS contract.

Q32. Could you please confirm that the following are the summer periods for the respective EDC's:

PEPCO: 1 May - 30 Sep
DPL: 1 May - 31 Aug
BGE: 1 June - 30 Sep

A32. Summer periods for Pepco, Delmarva, and BGE are correct

Q33. If the percentage of renewables required by year (as enumerated in Exhibit B of the 2009 FSA) change during the course of serving load, will we owe RECs based on the amended percentages or on those percentages listed in Exhibit B? Can you confirm that 2011 Tier 1 volumes will be based (taking into account all current legislation) on 3.040% of load?

A33. The 2009 FSA addresses changes in a Seller's Renewable Energy Obligation if the Renewable Energy Portfolio Standard is changed by law or regulation during a delivery period or for a multi-year Transaction. Changes that occur after the effective date of the 2009 FSA will be governed by Articles 4.4 (a) and 4.4 (b) of the 2009 FSA.

Q34. Similar to the current PLC values provided by the utilities, can each of the utilities provide their planning year 2009/2010 PLCs broken out by rate class and by on and off service customers.

A34. *BGE information*:

The data is provided for the March 31, so it would be comparable with historical data posted on rfp.BGE.com.

2009/2010 Capacity PLC
SNAPSHOT
For March 31, 2009
As Of April 13, 2009

WEBSUPPLIER	SUM(kW)
PRXPRXC	83,109
PRXPRXX	3,229,112
PRLPRLC	8,036
PRLPRLX	302,311
PL2GLXC	940,886
PL2GLXX	398,564
PL2GSXC	13,614
PL2GSXX	8,920
PL2GXXC	153,388
PL2GXXX	200,444
PL2PXXC	36,777
PL2PXXX	2,015
PL1GSXC	1,566
PL1GSXX	2,508
PL1GXXC	76,743
PL1GXXX	258,017
PL1PLXC	-

PL1PLXX -

-

PL1SLXC

-

PL1SLXX

OTHOTH- 1,486,529

Allegheny Power Information:

Estimated PLC effective 6/1/2009	PLC Data		
	All Eligible	**Default Service**	**Other Suppliers**
	PLC kW @ gen	PLC kW @ gen	PLC kW @ gen
Type I	**60,897**	**48,748**	**12,149**
Type II	**341,401**	**142,894**	**198,507**
Type H	**262,690**	**44,911**	**217,779**
Type R	**689,631**	**689,433**	**198**
Total	**1,354,619**	**925,986**	**428,633**

PHI Information

Delmarva MD		6/1/2009 CPLCs as of April 15, 2009	
Service Type	Class	KW SOS CPLC	KW Eligible CPLC
Type I	OL & ORL	12	12
Type I	GS-SH	10,048	17,663
Type I	GS-WH	26	26
Type I	SGS-S <25 kW	45,371	57,566
Total Type I		**55,457**	**75,267**
Type II	GS-P	2,062	19,641
Type II	LGS-S	8,119	54,024
Type II	SGS-S	72,340	153,619
Total Type II		**82,521**	**227,284**
Residential	R	469,284	474,610
Residential	R-TOU-ND	253	253
Total Residential		**469,537**	**474,863**
Total		**607,515**	**777,415**

PEPCO MD		6/1/2009 PLCs as of April 15 2009	
Service Type	Class	KW SOS CPLC	KW Eligible CPLC
Type I	GS-T-EV	83,092	117,272
Type I	SL	0	0
Type I	TN	2,261	2,261
Total Type I		**85,353**	**119,533**
Type II	MGT-3A	4,606	15,983
Type II	MGT-LV	288,326	941,348
Total Type II		**292,932**	**957,332**
Residential	R	1,226,971	1,320,271
Residential	R-TM	273,740	299,986
Total Residential		**1,500,711**	**1,620,258**
Total		**1,878,997**	**2,697,123**

Q35. For the June 8th auction, what is the latest date on which finalized historical usage data will be updated by the utilities?

A35. ***BGE*** can provide historical data update with the next month records by COB June 2nd.

Pepco and Delmarva have posted finalized historical usage data through February 2009. An estimate of DAYAFTER GEN LEVEL LOAD for March through May 22 2009 will be posted on Friday May 29th

Allegheny is not planning any additional updates to historical usage data prior to June 8.

Q36. Are the PLC values provided based on planning year 2008/2009 or planning year 2009/2010?

A36. ***BGE*** will provide historical capacity data update for the last day of the last month, i.e. 5/31 (PLCs for 2008/2009 DY) and extra set of records for 6/1/2009 (PLCs for 2009/2010 DY).

Pepco and Delmarva posted PLC values are based on the PJM planning year 2008/2009. An updated preliminary bid plan and PLCs for June 1, 2009 (PJM planning year 2009/2010 will be posted on the RFP Websites on Thursday May 28, 2009

Allegheny's PLC values are based on planning year 2008/2009. Files containing updated PLC information for the 2009/10 planning period will be made available on the RFP website on Friday, May 29, 2009..

****

September 24, 2008 Pre-bid Conference – Q&A

Q1. When will final bid plans and bid form spreadsheets be posted?
A1. Bid plans and bid form spreadsheets will be posted on the websites as scheduled in RFP section 6. The line in the schedule is described as: "Issue revisions to bid block targets". For the October auction it is scheduled that updated bid form spreadsheets will be posted on October 13. In general, the schedule calls for the last bid data release to occur one week before bid day.

Q2. When is the PLC base defined for purposes of volume risk?
A2. The base PLC is set on the first day of delivery for the Residential and Type I contracts. Defining a base PLC for Type II is not applicable since Type II does not have a volume risk mitigation mechanism.

Q3. Where is power delivered under the FSA?
A3. Sellers deliver into PJM. Settlement is at a specifically defined node, defined in the FSA, for each buyer. Any transmission congestion cost to the settlement node is the responsibility of the seller.

Q4. How does a seller determine the value of ARR's that accompany the load?
A4. The utilities are not privy to the methods used by suppliers to value ARRs before the FTR auctions.

Q5. The FSA specifies renewable requirements by year. Are those years calendar or PJM?
A5. The renewable requirements are specified by calendar year.

Q6. How often and when can the base in the volumetric risk mechanism be reset?
A6. The base is reset whenever the PLC moves down (decrements) by 3 MW or more. The base is reset at the original base less 3 MW and will be reset again if further decrements of 3 MW occur. There is no limit to the number of possible resets.

Q7. Does the base also reset on positive (incremental) changes?
A7. No.

Q8. What is the potential impact on utility customers if a seller defaults?
A8. All SOS-related costs are passed through to customers and hence any added costs from a failure-to-perform would be borne by customers. Any damages or settlements recovered by the utility would similarly be for the benefit of its customers.

Q9. Over what period is the mark-to-market calculated?
A9. The mark-to-market calculation covers the remaining period of the contract. It initially uses quantities based on the quantities stated on the transaction confirmation and forward prices that are provided by an independent pricing agent retained by the utilities.

Q10. Is there a requirement that initial security be provided by the seller?
A10. No. Security is only required when the mark-to-market exceeds the seller's unsecured credit limit by $500,000 or more.

Q11. What changes were made to facilitate participation by non-US owned sellers?
A11. Changes were made to the definition of Tangible Net Worth clarifying that it may be calculated according to the standards of governing bodies of jurisdictions outside the United States. The requirements for foreign entities are outlined in Section 14.6 of the FSA.

Q12. What are the ramifications of the current financial issues at Constellation?
A12. Neither the proposed MidAmerican transaction, nor any other issue confronting Constellation Energy has ramifications on BGE's Standard Offer Service. BGE is an independent SEC registrant with an independent credit rating and independent access to credit facilities.
****

ALLEGHENY POWER-SPECIFIC QUESTIONS AND ANSWERS

AP Q1. **Please provide the number of bid blocks and length of contracts awarded for Allegheny's residential procurements which took place on 10/22/07, 1/14/08, 4/21/08, and 6/9/08.**

	Procurements			
Term	10/22/07	1/14/08	4/21/08	6/9/08
Contract term beginning January 1, 2009				
1/1/09 - 5/31/09 (5 months)		2	1	1
1/1/09 - 5/31/10 (17 months)	3	2		
1/1/09 - 5/31/11 (29months)			2	1
Contract term beginning June 1, 2009				
6/1/09 - 5/31/10 (12 months)				1

AP Q2. **This question is regarding the retail rate structure for Allegheny residential customers after January 1, 2009. Based upon the procurement schedule, it appears that a rate for January 1, 2009-May 31, 2009, will be set (and released) by the beginning of November. Is this 2009?**

AP A2. Yes, a new rate will be released by the beginning of November, and the rate will change again in June.

AP Q3. **In the AP Type 2, Primary load, why is there a drop off in load from April 1, 2005 to May 1, 2005?**

For the General Services Type II Sec Load, why are there drop offs in the periods: 07/13/2005 – 07/28/2005 and 04/01/2008 – 05/01/2008? Also, why does the load peak in February 2007?

For the General Services Type II Sub Load, could you please explain the spike in usage during the period 03/27/2008 – 04/01/2008?

Can you please explain the calculations used in the Type II load data in the file provided? The load data is based on formulas until April 2007, after which it only has hard-coded numbers.

AP A3. It is not possible to determine why there is a drop off in load from April 1 to May 1, 2005. This would require examination of each customer in this class at that time and the individual customer history is no longer available for 2005.

It is not possible to determine why there are drop offs in the General Service Type II Sec load from 7/13/2005 to 7/28/2005 due to the age of the data. The

drop in load from 4/1/2008 to 5/1/2008 is similar to the load drop for the same time period the previous year. April is an off-peak month where both heating and cooling loads are minimized due to the mild temperature. The peak load in February 2007 is also weather related. Maryland experienced extreme lows in February with several days of minimums at or near zero degrees F. The Allegheny 2007 annual system peak load occurred in February as well.

For the General Service Type II Sub load, the load appears to be incorrectly doubled these few days from 3/27/2008 to 4/1/2008. The load is representative of only one customer and looks like the customer got picked up twice on these dates.

A formula is used until April 2007 to add a percentage of load from Type I to Type II in order to represent the change in the Type II definition historically prior to having these customers identified in our systems.

AP Q4. Please provide the NSPL that will be effective 1/1/09 and the Capacity PLC that will be effective 6/1/09 for the Allegheny Power Residential Load.

AP A4 The 1/1/09 NSPL value for the MD residential load is 718 MW. The MD Residential PLC effective 6/1/09 is approximately 690 MW.

AP Q5. Can you indicate whether the historical load data (e.g. under Residential, lasted updated on 12/22/2008) is at the retail meter level or generation level for APS? A question (not an answer) in the FAQ indicates that it's retail meter level (i.e. does not include T&D losses).

AP A5 The historical load data is provided at the retail meter level - excluded T&D losses.

AP Q6. Line losses are split out by P and OP and Secondary, Primary, Subtransmission and transmission for Allegheny Power.
Could you please confirm whether de-ration is included in these loss numbers? (Are the transmission losses of 2.245% and 2.028% the de-ration factors).
Could you please also confirm that the loss rates are cumulative (eg. total On Peak losses are 9.513% up to secondary transmission).

AP A6 The de-ration is included in these loss numbers - however the transmission losses of 2.245 % and 2.028 % are not representative of the PJM de-ration factors for the APS Zone. Historically, the de-ration factors for the APS zone have averaged about 3.5 to 4%.
Yes , the loss rates are cumulative. The secondary on-peak loss factor of 9.513% represents the total losses from transmission to the secondary meter service entrance.

AP Q7. In a recently posted file on the APS site, there is a file titled " MD PLC NSPL by Type for PAT". There is an adjustment footnoted in the spreadsheet referred to "Adjusted by PJM daily Adjustment Factor....LSE PLC...Zone PLC". The number works out to be 2%. Is that 2% a fixed number and one that will carry forward or does that value change over time?

AP A7. The PJM daily adjustment factor is calculated daily. Its the ratio of the sum to all the Allegheny LSEs PLCs compared to the Allegheny Zone PLC. It does change daily due to customer attrition but the change is typically neglible from day to day but trends upward over time the further away we get from June 1. Expect this adjustment factor to reset each June 1.

AP Q8. Is Allegheny going to go to weekly settlements for the MD Auction load in PJM effective 6/1?

AP A8. Yes.

AP Q9. Can you tell me if any power has been purchased for Allegheny Maryland Type I customers past June 2010? It appears that Type I load was not included in the 2009 Procurement.

AP A9. Current contracts for Type I customers expire May 31, 2010. There were no Type I procurements in the Allegheny Power 2009 procurement process.

PEPCO AND DELMARVA-SPECIFIC QUESTIONS AND ANSWERS

PHI Q1. I'm in the process of uploading the DPL and PEPCO documents to the website. However, there is a checkbox that also asks that these signed forms be sent by mail or fax. Is this required? And if so, where would you like the forms to be sent or faxed?

PHI A1. The check box which appears on the various DPL and PEPCO documents stating signed forms be sent by mail or fax, applies only if the applicant is submitting an electronic form with no electronic signature.

As stated in the RFP, signed forms maybe sent/faxed to:

PEPCO MD RFP Coordinator
Pepco Holdings Inc.
Suite 6411
Washington, D.C. 20068
Fax Number (202) 872-3350

Or

Delmarva MD RFP Coordinator
Pepco Holdings Inc.
Suite 6411
701 Ninth Street, N.W.
Washington, D.C. 20068
Fax Number (202) 872-3350

PHI Q2. The data provided for February 2008 for the DPL SGS classes in both Type I and II conflicts with that which was provided in the previous auction. Would you be able to shed some light as to what has caused this?

There are sharp drops throughout the Type I load. For example, on March 9, 2008, the GSSH load falls from 14 MW to 5 MW. It also happens on March 11, 2007. The drops occur simultaneously for the GSSH, GSWH and SGS classes. Could you please explain?

PHI A2. The Type I and Type II classes were redefined by the MDPSC, and took effect on June 1, 2008. Load values presented prior to that date are defined as estimates, and are subject to change. Actual values for the redefined classes begin with the June 2008 historical data files.

The March 9, 2008, and March 11, 2007 drops are a result of the Daylight Savings Time shift where Hour 3 is missing and set to zero.

PHI Q3. **The historical load data provided for the SGS (Type 1) class has a sudden and large increase starting June 1, 2008 and continues till approximately June 15, 2008. The historical PLCs do not reflect this increase so it does not seem to be an increase in the number of SGS customers. Can you please provide an explanation as to why we see this increase?**

PHI A3. The explanation for the SGS Type I peak load around June 9 is due to the profile model response to its season, day type and weather drivers. The load is also a function of the consumption for all members of the classes which use this profile. In this case, all of the SGS series classes. The Delmarva zone annual peak was June 10 at 1700. The weather was extraordinarily hot.

PHI Q4 **When will bid plans be posted for Pepco and Delmarva for the Jan 12th solicitation?**

PHI A4 Updated bid plans have been posted on the MD Pepco and Delmarva websites.

PHI Q5. **I'd just like to confirm that the ARR Auction Results posted to the PEPCO and DPL websites are for the 2009/2010 planning year.**

PHI A5. Yes, the ARR Auction Results posted to the PEPCO and DPL websites are for the 2009/2010 planning year

PHI Q6. **What caused the Delmarva's Type II Load to drop significantly from March 6th through the 8th? The data in question is in the file called DPL MD DAYAFTER GEN LEVEL LOAD FEBRUARY THRU APRIL-8-2009.xls posted on April 13th, 2009. Over the course of the three days the total eligible MWhs of Type II load dropped 47% from 3,093 MWhs to 1,638 MWhs and has stabilized well below its previous level. Can we expect the Type II load to remain at this new lower level? Does the drop in load have anything to do with the fact that March was the beginning of an new auction period?**

PHI A6. PHI is currently reviewing the issue with the Type II load data in the DPL MD DAYAFTER GEN LEVEL LOAD FEBRUARY THRU APRIL-8-2009 file posted on April 13th, 2009. The Type II load data within this file may be subject to change. Revisions if necessary to the Type II load will be posted immediately.

PHI Q7 **For DPL and PEPCO, are the provided NSPLs for all SOS and for all Eligible?**

PHI A7. Yes, DPL and PEPCO, provided NSPLs are for all current SOS customers and all Eligible (=SOS+Third Party).

PHI Q8. **Prior to the April procurement, each of the MD EDC's provided a PLC snapshot based upon the summer 2008 PLCs (see Q34).**

Delmarva placed the PLC for Type II at 82.5MW.
The 5/20 Bid Plan shows 55 MW, just like the April '09 bid plan did.
Shouldn't we expect the bid plan to expect a PLC more similar to the snapshot provided in the FAQs (~82 MW)

PHI A8. The Pepco and Delmarva posted PLC values are based on the PJM planning year 2008/2009. An updated preliminary bid plan and PLCs for June 1, 2009 (PJM planning year 2009/2010) will be posted on the RFP Websites on Thursday May 28, 2009. The June 1, 2009 SOS PLC will be similar to the snapshot provided in the earlier FAQs about 82 MW.

BGE-SPECIFIC QUESTIONS AND ANSWERS

BGE Q1 **Could you provide more detail in reference to Section 4.2 Load Response Programs sections (d) and (e), of the FSA.**

a) What notification does the Seller have there is a need to approve BGE's registrations?
b) Define the applicable load weighted Res, Type I, and Type II Monthly Settlement Base prices.
c) Define Sellers Monthly Settlement Load
d) How will seller notify Buyer reductions need approved?

BGE A1. a) Upon buyer's entry of a new registration in the eLoadResponse system PJM system sends an automated e-mail to a seller with the request of approval of the registration.

b) Seller may serve combination of several contracts of up to three load types: Residential, Type I, and Type II. Each service type and customer class within the type are affected differently by the load reduction, also each served energy contract has a unique set of prices by the customer class. The average contract/class price weighted by the load reduction impact kWh in the contract \class is calculated and provided during registration (see a)) as the retail price to be paid to seller in the settlement under the eLoadResponse system. Note that BGE invoice will pay only for the restricted loads. Payment for the restriction amount comes from PJM's eLoadResponse system. See PJM load response settlement rules for more details.

c) Seller's Monthly Settlement Load in the description of the FSA section 4.2 d) and e) is a reference to the restricted load which results after the load restricting events occurred. The restricted load, Monthly Settlement Load, is settled in the eSchedule system, while the load reduction applicable to that load is submitted by buyer and settled by PJM in the eLoadResponse system.

d) Similarly as in the registration event described in the point a), the act of submission of the load reduction by buyer into the eLoadResponse system will trigger automatic notification email sent by PJM system to the registered seller to approve the impact.

BGE Q2. **The total eligible load data (SOS + COMP) for the P class (Type 2) has sudden shifts in levels which we are concerned about. On June 1, 2006 the data level increases considerably over the level in the months preceding it. There is a similar increase in June 1, 2007 over the previous year of data.**

The total eligible load data (SOS + COMP) for the GS class (Type 1) also has sudden shifts in data, in particular on the following dates: October 1, 2005, June 1, 2006, April 1, 2008, and also on June 1, 2008.

If these are not data errors, can you please shed some light on what is driving the sudden data shifts.

BGE A2. Historical data matches historical settlements submitted to PJM.
Both classes mentioned in the question: GS and P constitute a small portion of the type I and type II load respectively. These classes contain relatively small

number of the largest customers in the load type, and the larger customers shop more than smaller customers. If you look on the whole SOS type I or type II load, the shifts in the load pattern disappear. Some of the jumps may be caused by P account reclassifications between type II and Hourly service and GS account reclassification between types I and II. Such reclassifications occur annually on June 1. Also note that before June 2008 BGE has not tracked current G and GS boundaries which are currently defined between types I and II. All historical settlement data for G and GS classes was split based on multiple assumptions and is as accurate as we could make it.

BGE does not track all load shifts and reasons for them to occur. Every shift can have a different trigger and answering such questions for every date would require a separate investigation.

BGE Q3. **Could you please confirm whether the BGE system loss factors are additive or multiplicative?**

Basically I'm after the equation to get from Zone Load Settled by PJM to the Premise Load with allocated UFE.

My initial guess is: Premise Load with allocated UFE = Zone Load Settled by PJM/ (1+deration factor)*(1+BGE loss factor)?

Also, could you please confirm the loss factors that i should be using for the Residential classes (R, ES and RL) to get from the Zone Load settled by PJM to the premise load with allocated UFE?

I have the following voltage class loss factors from your website:

Primary	
230 kV	**.878%**
115 kV	**1.622%**
34 kV	**2.473%**
13 and 4 kV	**3.66%**
secondary	**6.665%**

BGE A3. Loss factors are multiplicative, but how should they be applied is explained in the documents contained in the BGE historical data zip file on the Home and Due Diligence pages of the rfp.BGE.com site. Please read the included word document and PDF file to learn about the marginal losses. Then read the text below.

Loss factors from the BGE web site and presented in this question are accounting for all losses below 500kV. All residential and type II load is a secondary service load so secondary loss factor applies. Therefore they are containing partially PJM deration factor! That complicates somewhat calculations and makes the equation presented in this question invalid.

Note that deration factor although expresses transmission losses is not constructed by PJM like a normal loss factor. Deration factor equation is defined as:
(1 - PJM Deration Factor) * Generation Load = PJM Settlement Load

While the traditional transmission loss factor would be defined by the following equation:
Generation Load = PJM Settlement Load * (1+Transmission Loss Factor)

From the above equations one can see that PJM Deration Factor has a different value then the traditional loss factor.

BGE loss factors are traditional loss factors. PJM 500 kV loss factor, occurs above the BGE loss factors is also a traditional loss factor. Traditional loss factors are multiplicative. Therefore, the loss equation for the BGE Premise load with UFE is:
Generation Load = BGE Zone Premise Load with UFE * (1+ BGE Loss Factor) * (1+ 500kV Loss Factor)

From the general equations presented above we can obtain following set of equations for the secondary load served at BC (BGE) node:

BGE Zone Premise Load with UFE = Generation Load / (1.06665 * 1.005)
Where:

- 0.5% is the average 500kV loss factor. PJM calculates hourly factor values for the BC(BGE) Zone.
- 6.665% is a secondary loss factor used by BGE.

and

PJM Settlement Load = Generation Load * (1 – 0.014)
Where:

- 1.4% is the average deration factor. PJM calculates hourly factor values for the BC(BGE) Zone.

If one would like to write the equation presented in this question it would have to look as follows:

Premise Load with UFE = (PJM Settlement Load / (1 - PJM Deration Factor)) / ((1+ BGE Loss Factor) * (1+ 500kV Loss Factor))

Following the example above, an equation for the secondary load served at BC (BGE) node
Premise Load with UFE = PJM Settlement Load / (1 – 0.014) / (1.06665 * 1.005)
Where:

- 0.5% is the average 500kV loss factor. PJM calculates hourly factor values for the BC(BGE) Zone.
- 6.665% is a secondary loss factor used by BGE.
- 1.4% is the average deration factor. PJM calculates hourly factor values for the BC(BGE) Zone.

BGE submits hourly Generation Load numbers by eSchedule contract to PJM eSchedule system. PJM calculates the hourly deration factors and derates the loads submitted by the utility.

Also each SOS supplier serving load gets a daily report of detailed eSchedule load as defined in the FSA section on data sharing (section 3.3 in 2008 and 2009 FSA). Both the PJM submission and BGE report delivered daily to load serving supplier contain hourly Generation Load data. From the Generation Load SOS supplier can estimate Premise Load with UFE and the PJM Settlement Load using the equations presented above. The estimate can be converted into the exact calculation if the hourly values for both: (i) deration factor and (ii) 500 kV loss would be used in the calculation. Both values are calculated for each hour by PJM. BGE makes that exact hourly calculation summarizing monthly loads when producing monthly invoice for each supplier.

BGE Q4. Could you please provide the NSPL for the eligible and SOS customers by class for the BGE procurement?

BGE A4. BGE NSPL data:

10/14/2008 SCALED NSPL	SOS	Eligible
PL1	267.7	325.0
PL2	658.2	1,794.7
Res	3,464.7	3,561.8

BGE Q5. On page 7 of Model RFP 2009 (dated on September 10, 2008), Block size in %, Block size in MW, and Block # don't match. If the block size is 1.470588%, then the block size should be 25.1 MW and Block # should be 68. If block size is 50.2 MW and the block number is 34, then block size should be 2.94256%. The same problem is in Type 1. Please let me know the right block size.

BGE A5. The Residential and Type 1 Loads are auctioned in quarters, i.e. quarter of Residential and quarter of Type I load is auctioned twice a year for the two year term. Therefore the auctioned energy is a quarter of the energy to be served, and the number of blocks is a quarter of blocks you suggest we shall have: suggested 68 blocks must be divided into 4 quarters of 17 blocks auctioned in present auction. Also if we agree that there are 68 blocks total out of which only 17 are on auction at current auction, then each block has 1.470588% of the total eligible load. Total eligible load can be calculated as 853.0 MW to be awarded at this auction times 4 equal 3412MW. The percentage is applied to the total eligible: 3412MW * 1.470588% = 50.2MW.

The residential block size estimated at the time of RFP posting is 50.2. If you get to the rfp.BGE.com website and see the latest Bid Plan or Bid Form Spreadsheet for October 20th bid, the residential block size is estimated today at 50.3. The block size will change every day as retail customers can sign with competitive supply or return to SOS service at any time, also population can shrink or grow.

The block size on the first day of the power flow will define so called Base Bid Block size for all Residential and Type I contracts. See the volumetric risk mitigation – increment and decrement description in

section 6.2 of FSA Summarizing FSA: block size is variable, it changes every day, but supplier responsibility is capped at the Base Bid Block plus 5MW only. Base Bid Block can never grow, but in case of large outflow of retail customers to competitive supply the Base Block Size is subject to decrement to match reduced block size of the contract.

BGE Q6. **Could you please provide clarifications to the following points? Does the Supplier get paid by the Buyer for the load at the "Premise + UFE" load level and is then be obligated to procure a higher load at the "PJM Settlement Load" level? If so, what is the difference between the two?**

BGE A6. Both PJM settlement and BGE-supplier invoice include UFE. See historical data posted on BGE website rfp.bge.com. The data has two loads for every hour. The higher load is the wholesale PJM settlement load. The lower load is the retail BGE invoice load. Also see documents explaining loss calculation in BGE settlements they are included in the historical data ZIP file.

Also read an answer to BGE Q3 question in 2009 Q&A.

BGE Q7. **Could you please provide clarity on the number of Residential bid Blocks that will be solicited on Jan 12, 2009 for BGE service territory? It looks as though as many as 34 Blocks might be solicited - is this true?**

BGE A7. Only 17 Residential bid blocks will be solicited on January 12, 2009 for the BGE service territory. A new bid plan will be posted on the website Monday, January 5, 2009 reflecting the most up-to-date information.

BGE Q8. **When will the BGE bid plan for the April 16, 2009 procurement be posted?**

BGE A8. According with the section 6 of the Model RFP 2009, page 19, the auction is held on April 20, 2009. Final revisions of the bid plan (block size and number of blocks) are due on April 13, 2009. Files will be posted on rfp.bge.com and on the usual bid site.

Note that the block size posted in the bid plan posted before the January auction is a good indication of the revised block size available in the future. Also note that the block size is maintained at around 50 MW. That rule may change number of blocks posted in the plan, and the resulting size of each block. If the total SOS MW would grow above a certain threshold one more block will be added and the individual auction block size will fall below 50MW. Similarly, if the total SOS MW would fall below a certain threshold one less block will be curved for an auction and the individual block size will jump above 50MW.

BGE Q9. **The BGE data file containing NSPL and PLC data has an additional WebSupplier "OTHOTH-" for the date "31-Mar-09". Should this data be included in another WebSupplier ID or should this be excluded from our analysis?.**

BGE A9. Per supplier request the line with Web Supplier = ”OTHOTH-“ was added to show the rest of the BGE system. It is not part of any SOS eligible load.

BGE Q10. **Where can I find the posting of BGE Auction Results from April 2009 Solicitation?**

BGE A10. Here is the link to the results of the BGE SOS Auctions on the BGE website bge.com.

http://www.bge.com/portal/site/bge/menuitem.dff8c30cc1fa2858047eb471016176a0/