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GULF POWER
A SOUTHERN COMPANY

May 12, 2009

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COMMISSION CLERK

Ms. Ann Cole, Commission Clerk
Office of the Commission Clerk
Florida Public Service Commission
2540 Shumard Oak Boulevard
Tallahassee FL 32399-0850

Dear Ms. Cole:

RE: Docket No. 090169-EI

Enclosed is an original and 5 copies of Gulf Power Company's responses to Commission Staff's First Data Request in the above-referenced docket.

Sincerely,

Susan D. Ritenour

mv

Enclosures

cc w/encl.: Beggs & Lane
Jeffrey A. Stone, Esq.

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ECR ____
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SGA ____
ADM ____
CLK ____

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FPSC-COMMISSION CLERK

1. What is the origin and amount of the "avoided cost" Gulf Power used in evaluating the cost-effectiveness of the PPA?

   Response:

   Gulf Power's most recent Ten Year Site Plan indicates that its next planned generating unit (without this PPA) is an 840 MW combined cycle unit, with Plants Crist and Smith listed as potential sites for the new unit. At the point in time when this PPA opportunity surfaced, Plant Crist was the leading candidate in the ongoing evaluation of the sites for Gulf Power's next planned generating unit. As a result, the savings that Gulf Power estimated in its Petition for Approval of Purchased Power Agreement between Gulf Power Company and Shell Energy North America (US) are based upon comparisons between the PPA and an 840 MW combined cycle unit located at Plant Crist (Crist 8). Attachment A of the Petition for Approval of Purchased Power Agreement between Gulf Power Company and Shell Energy North America (US) shows the benefits associated with having the PPA and postponing the next planned generating unit. The response to Question 20 below provides more details regarding the cost-effectiveness of the PPA, and it lists projected costs with and without the PPA (2010$).

2. Is there a minimum purchase specified in dollars, capacity (kW), or energy (kWh) by the PPA between Shell Energy and Gulf Power?

   Response:

   Gulf will purchase the entire Central Alabama unit capacity and be entitled to commit, schedule, and dispatch energy to economically integrate the unit into the system economic dispatch. The capacity of the unit will be determined in an annual performance test, and Gulf will make monthly capacity payments that are calculated by multiplying the contracted capacity rate applicable for the given period by the unit capacity determined by the annual performance test. There is no minimum amount of energy Gulf is required to take from the facility. Article 1 and Article 8.5 (g) of the contract outline the process for calculating the Minimum Adjusted Fired Hour Charge

3. How will the prices charged under the PPA compare to the cost of the same amount of "as available energy" in the general market over the term of the PPA?

   Response:

   Gulf interprets the meaning of the term "as available energy" as hour to hour or day to day energy purchases from the wholesale power market. The alternative for this PPA would have been an RFP process that would have compared all proposals to Gulf's proposed self build unit. Since all proposals received from the RFP would been compared to Gulf's self build unit, Gulf did not attempt to estimate what as available energy in the market would have been over the term of the agreement. As shown in Attachment A of the petition, Gulf compared the PPA against what would have been Gulf's self build unit. In addition to comparing capital investment in the self build to capacity payments of the PPA, Gulf used a dispatch model to determine the value of the

Central Alabama facility in terms of energy. Attachment A (page 2) shows the energy delta with and without the Central Alabama facility included in economic dispatch. With the Central Alabama unit included in dispatch, the energy savings were approximately $450M (NPV $2014) for the contract term.

It is also important to note that "as available energy" is not comparable to the first call right to capacity and energy from the Central Alabama unit pursuant to the PPA. By 2014, Gulf needs such a first call right for capacity and energy from a reliable resource in order to assure generation reliability for its customers.

4. Please explain if and how this PPA can be used for meeting capacity needs before 2014?

   Response:

   Gulf does not plan to use the Central Alabama unit to meet capacity needs prior to 2014 since the system already has sufficient resources to meet the 15% capacity reserve requirement. The transmission facility upgrades to enable firm transmission must first be completed and firm gas transportation must be secured before the Central Alabama unit could be used for meeting firm capacity needs prior to 2014. The necessary improvements will be completed in time to allow Gulf to incorporate this capacity into its system by the summer of 2014 if this PPA is approved.

5. If an RFP had been issued, what types of energy sources would have been anticipated to bid on the contract?

   Response:

   Had an RFP been issued, it would have invited proposals for all types of reliable capacity resources utilizing all types of fuels. However, Gulf expected that most proposals were likely to be from either new or existing primarily gas-fired generating units.

6. If Congress passes a cap and trade bill, does this PPA make ratepayers more or less vulnerable? Please explain the answer.

   Response:

   If a CO_2 cap and trade bill is passed by Congress, this PPA is likely to make Gulf's ratepayers less vulnerable to the costs resulting from the related facility's CO_2 emissions because of the protections afforded in Section 21 of the Agreement entitled Change of Law.

7. Reference paragraph 12 of the Petition. Why was the PPA between Shell and Gulf made not effective until approved by the Public Service Commission, while a previous agreement between Gulf and Bay County was effective, with energy being delivered and payments being made, prior to Commission approval?

Response:

Both PPAs resulted from arms length negotiations, and provisions of each regarding effective dates in relation to Commission approval were the result of these negotiations. Given the relative magnitude of the costs associated with the purchases and the difference in nature of each contract, Gulf believes each PPA's effective date to be appropriate.

8. Paragraph 14 of the Petition states that the SES IRP process reported in Gulf's 2009 Ten Year Site Plan (TYSP) employs a 15 percent system reserve margin. Please complete the four charts provided (also available in Excel format) to calculate the reserve margin during each year for the term of the contract (2009 – 2023):
   a. With the PPA in effect, summer and winter

      Response:

      Please note that the Southern electric system (SES) 15 percent reserve margin results from capacity additions made by each SES operating company to serve total SES load. Gulf's contribution to meeting system capacity needs may or may not result in it having a 15 percent reserve margin in each year.

   b. Without the PPA, indicating the alternate sources of generation to meet load (Resource Plan Changes), summer and winter

      Response:

      If the Gulf/Shell PPA does not become effective, Gulf has assumed for purposes of this response that its alternate source of generation would be an 840 MW combined cycle unit with an in-service date of June 2014. Gulf would either build this unit or purchase power from a similar source chosen from respondents to an RFP for market supplied generation alternatives to Gulf's self built combined cycle.

Reserve Margin Analysis with PPA

Summer

August of the Year	(1) Resource Plan Changes	(2) Current Projection of Gulf Unit Capability (MW)	(3) Current Projection of Firm Purchases (MW)	(4) Cumulative Generation Additions (MW)	(5) Cumulative Generation Removed (MW)	(6) = (2)+(3) +(4)+(5) Projection of Total Capacity (MW)	(7) Peak Load Forecast (MW)	(8) Summer DSM Forecast (MW)	(9)= (7)-(8) Forecast of Firm Peak (MW)	(10)= (6)-(9) Forecast of Summer Reserves (MW)	(11)= (10)/(9) Forecast of Summer Reserve Margin (%)
2009	Column (5):Scherer 3 unit power sale	2703	488	0	211	2980	2970	362	2608	372	14.3
2010	Column (4):Perdido Landfill Gas units added	2670	488	3	211	2950	3040	370	2670	280	10.5
2011		2668	488	3	211	2948	3132	378	2754	194	7.0
2012	Column (5):Scholz 1 & 2 retire	2655	488	3	303	2843	3180	386	2794	49	1.8
2013	Column (4):Scholz 1 & 2 convert to biomass	2655	488	95	303	2935	3252	395	2857	78	2.7
2014	Column (3):Peaking Purchase expires, Shell Firm Purchase begins	2645	885	95	303	3322	3320	403	2917	405	13.9
2015		2635	885	95	303	3312	3391	412	2979	333	11.2
2016		2635	885	95	303	3312	3446	420	3026	286	9.5
2017		2635	885	95	303	3312	3536	429	3107	205	6.6
2018	Column (5):Smith A retires	2635	885	95	335	3280	3632	436	3196	84	2.6
2019	Column (5):Pea Ridge retires, Column (4):CT generation added	2627	885	395	347	3560	3727	443	3284	276	8.4
2020		2627	885	395	347	3560	3790	450	3340	220	6.6
2021		2627	885	395	347	3560	3882	456	3426	134	3.9
2022		2627	885	395	347	3560	3980	462	3518	42	1.2
2023	Column (3):Shell Purchase expires, Column (4):Base generation added	2627	0	1835	347	4115	4076	466	3610	505	14.0

Note: Unit Capabilities shown in Column (2) include derates shown on Schedule 8 of Gulf's 2009 Ten Year Site Plan

Reserve Margin Analysis with PPA

Winter

January of the Year	(1) Resource Plan Changes	(2) Current Projections of Gulf Unit Capability (MW)	(3) Current Projections of Firm Purchases (MW)	(4) Cumulative Generation Additions (MW)	(5) Cumulative Generation Removed (MW)	(6) = (2)+(3) +(4)+(5) Projection of Total Capacity (MW)	(7) Peak Load Forecast (MW)	(8) Winter DSM Forecast (MW)	(9)=(7)-(8) Forecast of Firm Peak (MW)	(10)=(6)-(9) Forecast of Winter Reserves (MW)	(11)=(10)/(9) Forecast of Winter Reserve Margin (%)
2009	Column (5):Scherer 3 unit power sale	2750	0	0	211	2539	2759	439	2320	219	9.4
2010		2742	488	0	211	3019	2856	457	2399	620	25.8
2011	Column (4):Perdido Landfill Gas units added	2709	488	3	211	2989	2953	474	2479	510	20.6
2012	Column (5):Scholz 1 & 2 retire	2707	488	3	303	2895	3036	491	2545	350	13.8
2013		2694	488	3	303	2882	3121	510	2611	271	10.4
2014	Column (4):Scholz 1 & 2 convert to biomass	2694	488	95	303	2974	3183	529	2654	320	12.1
2015	Column (3):Peaking Purchase expires, Shell Firm Purchase begins	2684	885	95	303	3361	3242	548	2694	667	24.8
2016		2674	885	95	303	3351	3325	567	2758	593	21.5
2017		2674	885	95	303	3351	3426	586	2840	511	18.0
2018	Column (5):Smith A retires	2674	885	95	343	3311	3505	594	2911	400	13.7
2019	Column (5):Pea Ridge retires	2674	885	95	358	3296	3593	602	2991	305	10.2
2020	Column (4):CT generation added	2666	885	435	358	3628	3687	610	3077	551	17.9
2021		2666	885	435	358	3628	3791	616	3175	453	14.3
2022		2666	885	435	358	3628	3866	623	3243	385	11.9
2023		2666	885	435	358	3628	3959	628	3331	297	8.9

Note: Unit Capabilities shown in Column (2) include derates shown on Schedule 8 of Gulf's 2009 Ten Year Site Plan

Reserve Margin Analysis without PPA

Summer

August of the Year	(1) Resource Plan Changes	(2) Current Projections of Gulf Unit Capability (MW)	(3) Current Projections of Firm Purchases (MW)	(4) Cumulative Generation Additions (MW)	(5) Cumulative Generation Removed (MW)	(6) = (2)+(3) +(4)+(5) Projection of Total Capacity (MW)	(7) Peak Load Forecast (MW)	(8) Summer DSM Forecast (MW)	(9)=(7)-(8) Forecast of Firm Peak (MW)	(10)=(6)-(9) Forecast of Summer Reserves (MW)	(11)=(10)/(9) Forecast of Summer Reserve Margin (%)
2009	Column (5):Scherer 3 unit power sale	2703	488	0	211	2980	2970	362	2608	372.0	14.3
2010	Column (4):Perdido Landfill Gas units added	2670	488	3	211	2950	3040	370	2670	280.0	10.5
2011		2668	488	3	211	2948	3132	378	2754	194.0	7.0
2012	Column (5):Scholz 1 & 2 retire	2655	488	3	303	2843	3180	386	2794	49.0	1.8
2013	Column (4):Scholz 1 & 2 convert to biomass	2655	488	95	303	2935	3252	395	2857	78.0	2.7
2014	Column (3):Peaking Purchase expires, Column (4):CC generation added	2645	0	935	303	3277	3320	403	2917	360.0	12.3
2015		2635	0	935	303	3267	3391	412	2979	288.0	9.7
2016		2635	0	935	303	3267	3446	420	3026	241.0	8.0
2017		2635	0	935	303	3267	3536	429	3107	160.0	5.1
2018	Column (5):Smith A retires	2635	0	935	335	3235	3632	436	3196	39.0	1.2
2019	Column (5):Pea Ridge retires, Column (4):CT generation added	2627	0	1235	347	3515	3727	443	3284	231.0	7.0
2020		2627	0	1235	347	3515	3790	450	3340	175.0	5.2
2021		2627	0	1235	347	3515	3882	456	3426	89.0	2.6
2022		2627	0	1235	347	3515	3980	462	3518	(3.0)	(0.1)
2023	Column (4):Base generation added	2627	0	1835	347	4115	4076	466	3610	505.0	14.0

Note: Unit Capabilities shown in Column (2) include derates shown on Schedule 8 of Gulf's 2009 Ten Year Site Plan

Reserve Margin Analysis without PPA

Winter

January of the Year	(1) Resource Plan Changes	(2) Current Projections of Gulf Unit Capability (MW)	(3) Current Projections of Firm Purchases (MW)	(4) Cumulative Generation Additions (MW)	(5) Cumulative Generation Removed (MW)	(6) = (2)+(3) +(4)+(5) Projection of Total Capacity (MW)	(7) Peak Load Forecast (MW)	(8) Winter DSM Forecast (MW)	(9)=(7)-(8) Forecast of Firm Peak (MW)	(10)=(6)-(9) Forecast of Winter Reserves (MW)	(11)=(10)/(9) Forecast of Winter Reserve Margin (%)
2009	Column (5):Scherer 3 unit power sale	2750	0	0	211	2539	2759	439	2320	219	9.4
2010		2742	488	0	211	3019	2856	457	2399	620	25.8
2011	Column (4):Perdido Landfill Gas units added	2709	488	3	211	2989	2953	474	2479	510	20.6
2012	Column (5):Scholz 1 & 2 retire	2707	488	3	303	2895	3036	491	2545	350	13.8
2013		2694	488	3	303	2882	3121	510	2611	271	10.4
2014	Column (4):Scholz 1 & 2 convert to biomass	2694	488	95	303	2974	3183	529	2654	320	12.1
2015	Column (3):Peaking Purchase expires, Column (4):CC generation added	2684	0	995	303	3376	3242	548	2694	682	25.3
2016		2674	0	995	303	3366	3325	567	2758	608	22.0
2017		2674	0	995	303	3366	3426	586	2840	526	18.5
2018	Column (5):Smith A retires	2674	0	995	343	3326	3505	594	2911	415	14.3
2019	Column (5):Pea Ridge retires	2674	0	995	358	3311	3593	602	2991	320	10.7
2020	Column (4):CT generation added	2666	0	1335	358	3643	3687	610	3077	566	18.4
2021		2666	0	1335	358	3643	3791	616	3175	468	14.7
2022		2666	0	1335	358	3643	3866	623	3243	400	12.3
2023		2666	0	1335	358	3643	3959	628	3331	312	9.4

Note: Unit Capabilities shown in Column (2) include derates shown on Schedule 8 of Gulf's 2009 Ten Year Site Plan

9. Paragraph 15 of the Petition shows Gulf will need additional capacity to meet its projected load beginning with a 51 MW shortfall in 2010. The narrative, however, states that additional generation of 976 MW is not needed until 2014. How will Gulf meet its projected demand from 2010 until 2014?

   Response:

   Although Gulf has a small capacity need beginning in 2010, the Southern electric system (SES) is currently projected to have sufficient capacity on its system to reliably serve total system load until the summer of 2014. As noted in Paragraph 13 of the petition, Gulf's participation in the SES IRP process enables Gulf "to coordinate its capacity additions…in a manner that allows Gulf to utilize any temporary surpluses of capacity available on the Southern electric system that may result from large economic blocks of capacity added by other SES retail regulated operating companies." These temporary capacity surpluses will be available to Gulf through the reserve sharing provisions of the SES Intercompany Interchange Contract.

10. Paragraph 17 of the Petition states that the PPA "likely will result in net benefits to Gulf's customers over the contract years 2009-2013." Please quantify the monetary benefit to customers and show how this amount was calculated.

    Response:

    As shown in Attachment B of the petition, Gulf estimates a net present value (NPV) savings of $40 million dollars during the period. Production cost models were run with and without the PPA resource included in order to quantify each scenario's energy costs. The difference between the results of these two runs was determined to be a NPV energy cost savings of $110 million. Then the applicable generation cost (which includes 100 percent of the PPA capacity cost) and firm gas transportation cost (NPV $68 million) were added to the net energy savings to get the total short term savings.

11. Section VII of the Petition discusses transmission costs associated with the PPA. Attachment A to the Petition shows the transmission costs for a new Crist generator alone, and a new Crist generator plus the PPA. Why are transmission costs greater for building only a generation plant at the existing Crist facility compared to building the Crist facility plus transmission costs for the PPA over 200 miles from Gulf's service area?

    Response:

    The economic analysis summarized in Attachment A assumes that the PPA allows Gulf to defer the Crist combined cycle unit from 2014 to 2023 when the PPA expires. This also allows the construction of the transmission expansion to provide firm transmission service for the Crist capacity to be deferred from 2014 to 2023. The cost of the Crist transmission is assumed to escalate during this nine year period at the rate of general inflation. When the Crist transmission is installed in 2023, its revenue requirements will be included in plant-in-service at this escalated cost. However, the costs shown in Attachment A are presented as a 2014 net present value. Since the discount rate is much higher than the rate of general inflation, the net present value of Crist transmission cost is less than it would have been if the facilities were constructed by 2014. The net impact of these transmission cost components results in a somewhat lower net present value associated with the PPA compared to the alternative in which the Crist combined cycle unit is installed in 2014. The tables included in the Company's response to Question 20 of Staff's First Data Request show the yearly present value of the annual transmission costs for both the PPA and the Crist alternative.

12. Paragraph 27 of the Petition states firm transmission service for the generating plant is needed no later than June 1, 2014. Several necessary improvements are also discussed. Please explain how, without the improvements, energy will be delivered from the plant to Gulf's service territory between 2009 and 2014.

Response:

Gulf will not be relying on the PPA capacity for reliability prior to the summer of 2014. In order to maximize the net benefit of the PPA prior to that time, Gulf does not intend to provide firm transmission capability or firm gas pipeline transportation capacity for the unit. While some electric transmission or natural gas transportation curtailments are possible, Gulf expects to be able to operate the unit the vast majority of the time (and receive the projected energy cost savings) during the 2009 to May 2014 period without expanding the transmission system or purchasing annual firm gas pipeline transportation.

13. Attachments A and B to the Petition use the term "Central Alabama PPA." Please confirm that this term is synonymous with the Power Purchase Agreement between Shell and Gulf Power.

Response:

Yes.

14. Please provide a revision to the chart on page 1, Attachment A to the Petition that addresses the term of the PPA, 2009 to 2023.

Response:

In revising the chart on page 1, Attachment A to include the term of the PPA 2009 to 2023, please note that for the comparison of alternatives it is assumed that the Central Alabama PPA becomes effective January 1, 2010. Gulf Power anticipates that it would achieve additional benefits for its customers if the PPA commences prior to 1/1/2010.

As a result of the requested chart revision, please note that the discount year has been changed to 2010 to reflect the initial term of the comparison.

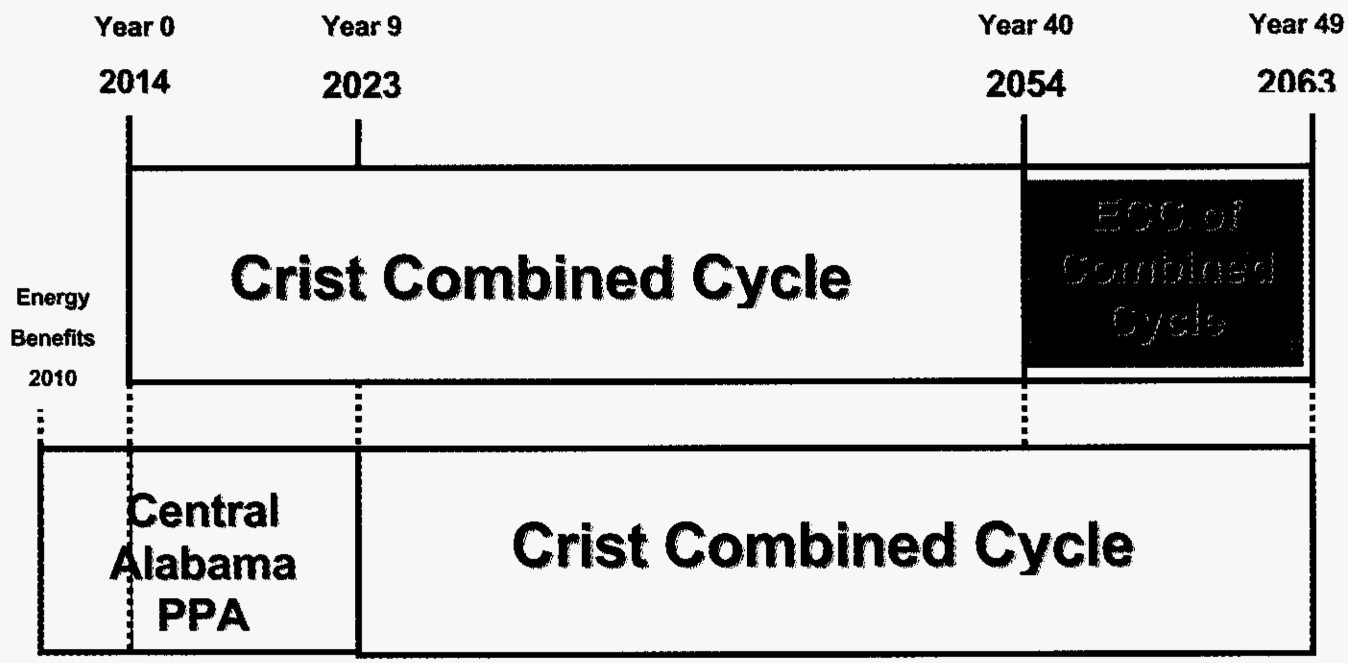
A revised page 1 of Attachment A is provided below. Attachment A to the Petition has been corrected to reflect the forty year period to 2054 and the forty-nine year period to 2063.

ATTACHMENT A

Central Alabama PPA Savings vs. Crist Combined Cycle

Net Present Value Comparison in $2010

A. Economic Analysis Study Methodology



Notes:

- **Assumes that Energy Benefit of Central Alabama starts January 2010.**
- **Assumes 9 Year Deferral of Crist Combined Cycle starting June 2014.**
- **Economic Carrying Cost (ECC) of replacement Combined Cycle to equalize study periods.**

15. Attachment A to the Petition lists "Energy Savings" on pages 2 and 3.
    a. Please explain how the energy savings listed were calculated.

    <u>Response:</u>

    As noted in the response to Question 14, the discount year has been changed to 2010 and as a result the information provided on this chart will not tie to the sum of the charts on Attachment A of the petition.
    The "Energy Savings" found in Attachment A are calculated using the Strategist production cost model (licensed by Ventyx, Inc., Atlanta, Georgia). Energy Savings for the Central Alabama option are calculated by first simulating the system dispatch with Central Alabama available as an integral part of the generating unit fleet and then running the simulation without Central Alabama. The Central Alabama "Energy Savings", which is found by taking the difference between the simulations, is the system cost reduction associated with having the Central Alabama facility in the dispatch.

    Similarly, the energy savings for the Crist 8 option can be calculated by running a simulation including and then excluding the Crist 8 asset.

    b. Please provide copies of the worksheets used in the calculation, in hard copy and electronic (Excel) format.

    <u>Response:</u>

    Information responsive to this request has been submitted pursuant to a separate Notice of Intent to Request Confidential Classification.

16. Attachment A to the Petition lists "Equity Cost" on pages 2 and 3.
    a. Please explain how the equity costs listed were calculated.

    <u>Response:</u>

    The "Equity Cost" found in Attachment A was calculated in two parts: (1) the short term (2010 – mid 2014) portion of the PPA, and (2) the longer term (mid 2014-2023) portion. This two tier approach was employed since the step up in capacity payments in 2014 results in a change in the level of imputed debt at that time. The annual equity cost of the Central Alabama PPA is the result of a 25% debt imputation on the fixed capacity payments of the PPA contract, and uses the methodology employed by Standard and Poor's in imputing the debt impact resulting from the transaction.

    For the short term portion (2010 - mid 2014), an equivalent remaining mid-year payoff balance is calculated using the payment schedule through mid-2014. The annual imputed debt amount is simply the mid-year payoff balance (calculated annually) multiplied by 25 percent. Since Gulf's target capital structure is 50% debt, 45% common equity, and 5%

preferred, the imputed debt must be offset by adding more common and preferred to cover 50% of the imputed debt balance. This additional equity investment results in a corresponding reduction in debt. Since the cost of equity is more expensive than debt, the additional cost is shown as the "Equity Cost". It is simply the additional cost above debt to bring the capital structure back to the 50% debt, 45% equity, 5% preferred level once the imputed debt is applied to the PPA.

The longer term (mid 2014-2023) is calculated in exactly the same manner.

b. Please provide copies of the worksheets used in the calculation, in hard copy and electronic (Excel) format.

Response:

Information responsive to this request has been submitted pursuant to a separate Notice of Intent to Request Confidential Classification.

17. Attachment B to the Petition shows no transmission costs for the purchased power from 2009 to 2013. Does staff understand correctly that transmission service will be provided at no charge for more than 4 years over the 200 miles to Gulf's service territory? Please explain.

Response:

Yes. Staff is correct that there are no charges to Gulf for transmission service associated with the Central Alabama unit prior to 2014. At present, the SES transmission system will not support firm transmission service between the Central Alabama unit and Gulf Power's load centers. As described in the Petition and in response to Question 12 of the Staff's First Data Request, Gulf intends to operate the Central Alabama unit as a non-firm energy resource until firm transmission service is available because of the transmission limitations and the fact that the SES does not require the unit for capacity purposes prior to summer 2014. During this period, the Southern system companies will be making transmission improvements that will allow for firm transmission to Gulf from the Central Alabama unit. Therefore, the transmission expansion necessary for firm transmission delivery is projected to be developed by 2013 to support the 2014 capacity need. Gulf will compensate other Southern system companies for its share of incremental transmission costs incurred for generating capacity resources (such as the Central Alabama unit) which are connected to the system outside of Gulf's service area. Gulf's payments as a result of the transmission expansion are included in the 2014-2023 analysis summarized in Attachment A.

18. What will be Gulf's generation fuel mix, including fuel to produce purchased power, with and without the PPA, in 2008 (before the PPA), in 2009, 2014, and 2023?

Response:

GULF POWER COMPANY
GENERATION FUEL MIX BY TYPE
with Shell PPA

	June 2008		*June 2009* (2)		*June 2014*		*June 2023*	
	MW	*%*	*MW*	*%*	*MW*	*%*	*MW*	*%*
Coal (1)	1900	76.0	1893	50.2	1742	52.4	1724	41.9
Natural Gas (3)	568	22.7	1940	49.0	1453	43.7	1696	41.2
Oil	32	1.3	32	0.8	32	1.0	0	0.0
Renewable (4)	0	0.0	0	0.0	95	2.9	95	2.3
Other (5)	0	0.0	0	0.0	0	0.0	600	14.6
Total	2500	100	3865	100	3322	100	4115	100

(1) Does not include Scherer 3 capacity dedicated to wholesale
(2) Includes Non-Firm Shell PPA Capacity
(3) See Question 8 response for capacity change details
(4) Excludes Non-Firm Renewable PPA
(5) Technology type for the 2023 capacity addition not yet determined

GULF POWER COMPANY
GENERATION FUEL MIX BY TYPE
Without Shell PPA

	June 2008		*June 2009*		*June 2014*		*June 2023*	
	MW	*%*	*MW*	*%*	*MW*	*%*	*MW*	*%*
Coal (1)	1900	76.0	1893	63.5	1742	53.2	1724	41.9
Natural Gas (2)	568	22.7	1055	35.4	1408	43.0	1696	41.2
Oil	32	1.3	32	1.1	32	1.0	0	0.0
Renewable (3)	0	0.0	0	0.0	95	2.9	95	2.3
Other (4)	0	0.0	0	0.0	0	0.0	600	14.6
Total	2500	100	2980	100	3277	100	4115	100

(1) Does not include Scherer 3 capacity dedicated to wholesale
(2) See Question 8 response for capacity change details
(3) Excludes Non-Firm Renewable PPA
(4) Technology type for the 2023 capacity addition not yet determined

19. Paragraph 1.1 of the PPA, page 14, "Energy Point of Delivery" defines the point at which Gulf Power receives the generated energy. In that regard, please respond to the following:
    a. Please discuss line loss amounts and considerations between the Energy Point of Delivery and Gulf's service territory.

       Response:

       Gulf is unable to supply a response at this time due to computer software problems, but anticipates sending the complete response by May15, 2009.

    b. What will be the annual retail value of the energy lost in transmission between the Energy Point of Delivery and Gulf's service territory?

       Response:

       See response to 19 a. above

20. Please illustrate sensitivity to cost-effectiveness of the PPA by completing the attached worksheets (also available in Excel format) for projections of low, mid, and high priced fuel, with and without the PPA.

    Response:

    The following notes are important to consider when reviewing the data shown in the attached tables:

    Customer Bill Impacts:

    (1) Customer bill impact amounts for each of the six scenarios are presented on a separate table because they are presented in $/month. All of the other values in the tables are presented in $000s present-valued to 2009 dollars as requested.
    (2) Customer bill impacts for each Scenario are calculated on the revenue requirement amounts (nominal dollars) for each year and are expressed in nominal dollars.
    (3) Costs included in columns D, E, and H of the tables are allocated on 12/13th demand and 1/13th energy.
    (4) Costs included in columns B, F, and G of the tables are allocated on energy.
    (5) Customer bill impact assumes retail and rate class level energy and demand loss multipliers from Gulf's 2001 Cost of Service Study Losses Analysis; 12 CP KW load factors and jurisdictional demand allocators are based on 2006 load research data consistent with other cost recovery clauses filed before the Florida Public Service Commission.
    (6) Customer bill impact calculations use projected KWH from Gulf's 2009 Official Budget Forecast. Long term energy projections assume ten year compound average growth rates over the period 2023 to 2033 to escalate the energy forecast beyond 2033.

(7) Customer bill impacts include revenue taxes consistent with cost recovery clauses before this Commission but do not include gross receipts tax.

Gas Price Assumptions:

(1) For each of the Low-level fuel cost scenarios below, the Natural Gas price used in Column C of the tables was reduced $2.00 (indexed to 2009) per mmBTU for the period 2014 and beyond. All other fuel prices reflect the mid or 2009 IRP D1 case.
(2) For each of the High-level fuel cost scenarios below, the Natural Gas price used in Column C of the tables was increased $2.00 (indexed to 2009) per mmBTU for the period 2014 and beyond. All other fuel prices reflect the mid or 2009 IRP D1 case.

a. Scenario 1.1 - Mid-level Fuel Costs, with Purchased Power Agreement

   Response:

   Information responsive to this request has been submitted pursuant to a separate Notice of Intent to Request Confidential Classification.

b. Scenario 1.2 - Low-level Fuel Costs, with Purchased Power Agreement

   Response:
   Information responsive to this request has been submitted pursuant to a separate Notice of Intent to Request Confidential Classification.

c. Scenario 1.3 - High-level Fuel Costs, with Purchased Power Agreement

   Response:

   Information responsive to this request has been submitted pursuant to a separate Notice of Intent to Request Confidential Classification.

d. Scenario 2.1 - Mid-level Fuel Costs, without Purchased Power Agreement

   Response:

   Information responsive to this request has been submitted pursuant to a separate Notice of Intent to Request Confidential Classification.

e. Scenario 2.2 - Low-level Fuel Costs, without Purchased Power Agreement

   Response:

   Information responsive to this request has been submitted pursuant to a separate Notice of Intent to Request Confidential Classification.

f. Scenario 2.3 - High-level Fuel Costs, without Purchased Power Agreement

Response:

Information responsive to this request has been submitted pursuant to a separate Notice of Intent to Request Confidential Classification.

Customer Bill Impact @ 1,200 kWh/Month
For Each Scenario
($/month)

	Year	Scenario 1.1 Mid-level Fuel Costs With Purchase Power Agreement	Scenario 1.2 Low-level Fuel Costs With Purchase Power Agreement	Scenario 1.3 High-level Fuel Costs With Purchase Power Agreement	Scenario 2.1 Mid-level Fuel Costs Without Purchase Power Agreement	Scenario 2.2 Low-level Fuel Costs Without Purchase Power Agreement	Scenario 2.3 High-level Fuel Costs Without Purchase Power Agreement
1	2009	-	-	-	-	-	-
2	2010	(2.88)	(2.88)	(2.88)	-	-	-
3	2011	(0.78)	(0.78)	(0.78)	-	-	-
4	2012	0.03	0.03	0.03	-	-	-
5	2013	0.42	0.42	0.42	-	-	-
6	2014	5.11	5.51	4.71	11.59	12.07	10.99
7	2015	6.58	7.34	5.79	18.29	19.10	17.24
8	2016	6.27	7.00	5.55	17.08	17.91	16.08
9	2017	4.70	5.71	3.57	14.23	15.44	12.92
10	2018	4.68	5.64	3.60	13.69	14.87	12.53
11	2019	4.81	5.76	3.90	12.82	13.84	11.72
12	2020	4.77	5.57	3.85	12.43	13.15	11.43
13	2021	4.52	5.28	3.56	11.34	12.18	10.13
14	2022	4.40	5.24	3.46	10.85	11.74	9.75
15	2023	15.54	16.04	15.03	12.85	13.35	12.29
16	2024	18.82	19.30	18.34	11.95	12.43	11.46
17	2025	17.86	18.32	17.41	11.36	11.82	10.91
18	2026	16.66	17.13	16.20	10.49	10.96	10.03
19	2027	15.82	16.24	15.36	9.93	10.36	9.48
20	2028	14.62	15.02	14.14	8.99	9.39	8.51
21	2029	13.59	14.10	13.07	8.18	8.69	7.66
22	2030	12.39	12.89	11.77	7.19	7.69	6.57
23	2031	11.11	11.77	10.38	6.11	6.77	5.38
24	2032	10.48	11.11	9.76	5.67	6.30	4.95
25	2033	10.06	10.62	9.52	5.43	5.99	4.89
26	2034	8.94	9.57	8.23	4.53	5.16	3.82
27	2035	8.24	8.84	7.53	4.13	4.73	3.42
28	2036	7.54	8.15	6.86	3.74	4.35	3.06
29	2037	6.63	7.32	5.88	3.14	3.83	2.38
30	2038	5.84	6.53	5.14	2.63	3.32	1.93
31	2039	5.40	6.10	4.64	2.45	3.15	1.69

	Year	**Scenario 1.1** Mid-level Fuel Costs With Purchase Power Agreement	**Scenario 1.2** Low-level Fuel Costs With Purchase Power Agreement	**Scenario 1.3** High-level Fuel Costs With Purchase Power Agreement	**Scenario 2.1** Mid-level Fuel Costs Without Purchase Power Agreement	**Scenario 2.2** Low-level Fuel Costs Without Purchase Power Agreement	**Scenario 2.3** High-level Fuel Costs Without Purchase Power Agreement
32	2040	4.74	5.41	4.00	2.04	2.70	1.29
33	2041	4.39	5.04	3.74	1.92	2.57	1.27
34	2042	3.22	3.95	2.41	0.97	1.70	0.16
35	2043	3.33	4.01	2.61	1.26	1.94	0.54
36	2044	3.00	3.68	2.29	1.03	1.71	0.32
37	2045	2.72	3.39	2.01	0.82	1.49	0.11
38	2046	2.45	3.11	1.74	0.61	1.28	(0.10)
39	2047	2.18	2.85	1.48	0.41	1.07	(0.30)
40	2048	1.93	2.59	1.23	0.21	0.87	(0.49)
41	2049	1.69	2.34	0.99	0.03	0.68	(0.67)
42	2050	1.45	2.10	0.76	(0.15)	0.50	(0.84)
43	2051	1.22	1.87	0.54	(0.32)	0.32	(1.01)
44	2052	1.01	1.65	0.32	(0.49)	0.16	(1.17)
45	2053	0.80	1.44	0.12	(0.65)	(0.01)	(1.33)
46	2054	0.59	1.23	(0.08)	3.78	4.42	3.11
47	2055	0.40	1.03	(0.27)	6.86	7.50	6.19
48	2056	0.21	0.84	(0.46)	6.80	7.43	6.13
49	2057	0.03	0.66	(0.63)	6.74	7.37	6.07
50	2058	(0.14)	0.48	(0.80)	6.68	7.31	6.02
51	2059	(0.31)	0.31	(0.97)	6.62	7.24	5.96
52	2060	(0.47)	0.15	(1.12)	6.56	7.18	5.91
53	2061	(0.62)	(0.01)	(1.27)	6.51	7.12	5.86
54	2062	(0.77)	(0.16)	(1.42)	6.45	7.06	5.80
55	2063	(0.30)	(0.05)	(0.57)	2.66	2.92	2.40
56	2064	-	-	-	-	-	-

21. Please explain the rationale for the variations in the confidential Capacity Reservation Rate Per Month, for 2009 through May 2014, shown in the PPA, Exhibit 4.1.

Response:

For the period prior to June 2014, the average Capacity Reservation Rate Per Month is as shown on Exhibit 4.1 of the PPA for the period June 2010 through May 2014. The monthly values for the first year (June 2009 through May 2010) are different because they have been shaped to match the weighted value of capacity across the different months. This shaping was necessary because the First Contract Year of the agreement is likely to be less than twelve months. Capacity is more valuable to Gulf Power during the summer months, and this is reflected by the first year's Capacity Reservation Rate Per Month values being higher for the summer months.

22. Please confirm that the confidential Capacity Reservation Rate Per Month, for June 2014 and each Month thereafter, shown in the PPA, Exhibit 4.1, is not a typographical error.

Response:

All data shown in Exhibit 4.1 is correct and reflects the agreement negotiated between the parties.

23. Please explain the rationale for Gulf Power being responsible for providing the natural gas to operate the generating unit rather than the generating unit owner/operator.

Response:

Gulf structured the agreement with Shell to take advantage of the economies of scale associated with managing this facility to fully integrate the natural gas transportation and commodity needs of Gulfs and the SES fleet of natural gas generators. This intent was consistent with Shell's intent to offer the unit in a tolling agreement where the purchaser would deliver fuel for conversion to electrical energy. The possibility of Shell supplying the natural gas was never offered or discussed. Therefore, Gulf cannot determine the variable energy rate that Shell would seek from Gulf if Shell were to provide the natural gas needed for the unit's operation.

24. Please prepare a chart similar to the one in the PPA, Exhibit 4.1, that shows the Variable Energy Rate if the owner/operator of the generating unit provided the natural gas for operation.

Response:

See response to Question 23.

25. Referencing Gulf Power's Ten Year Site Plan, 2009-2018, Schedule 9, please confirm that the proposed generating facility shown is the Crist combined cycle plant mentioned several times in the Petition.

<u>Response:</u>

The combined cycle generating facility shown on Schedule 9 of Gulf's 2009 Ten Year Site Plan is not Plant Crist site specific. The installed cost was developed from cost data also used in the Crist combined cycle analysis that was used in evaluating the cost effectiveness of the PPA compared to Gulf's self-build alternative, but the costs on Schedule 9 do not include the gas lateral cost and other costs specifically related to the Crist combined cycle plant that is referenced in the Petition. Also, the fixed O&M and variable O&M rates in the Ten Year Site Plan result from the latest system O&M engineering analysis of a generic "G" Combined Cycle unit.

26. Again referencing Gulf Power's Ten Year Site Plan, 2009-2018, Schedule 9, please confirm that the following cost projections for the facility indicated are still as accurate as possible:
    a. Total installed cost (In-service year $/kW): $1,132.00

    <u>Response:</u>

    The installed cost above is based on the most accurate engineering, procurement and construction costs that are currently available to Gulf. These costs were used in the Crist combined cycle analysis, but do not include the gas lateral cost and other costs specifically related to the Crist combined cycle plant.

    b. Fixed O&M ('14 $/kWh): 8.11

    <u>Response:</u>

    The Fixed O&M cost of 8.11 $/kW-Yr shown on Schedule 9 is based on the most accurate engineering data that is currently available to Gulf.

    c. Variable O&M ('14 $/MWH) 1.71

    <u>Response:</u>

    The Variable O&M cost of 1.71 $/MWH shown on Schedule 9 is based on the most accurate engineering data that is currently available to Gulf.

27. Should the two plants referenced in Question 25 not be one in the same, please provide the cost projections shown in Question 26 for the Crist combined cycle plant.

Response:

Total installed cost (In-service year $/kW):	1,279
Fixed O&M ('14 $/kW-Yr):	8.82
Variable O&M ('14 $/MWH)	0.59

28. Paragraph 5.2 of the PPA discusses Requests for Energy by Gulf. Under what circumstances would Gulf not request the full energy output of approximately 880 MW?

Response:

Gulf as part of the SES, uses economic dispatch to help ensure customers receive the benefit of the most economical resources available at any given point in time. The Central Alabama combined cycle unit will be economically dispatched along with the other SES generating units. Gulf would not request the full energy output of the Central Alabama unit if other more economical resources in the SES fleet are available.

29. Paragraph 5.7 of the PPA discusses actions to be taken when Shell is unable to meet Gulf's Request for Energy. For each year of the PPA term, please provide a projection of the cost to Gulf of "as-available" energy to replace the shortfall if Shell is unable to provide the energy in Gulf's Request for Energy compared to any payments to Gulf by Shell resulting from an unscheduled outage, as specified in paragraph 5.7.

Response:

The actual cost that Gulf Power will incur when replacing requested energy that Shell is unable to deliver will vary, depending on the year, the month, the day of the week, the hour of the day, weather conditions, and market conditions. Payments that Shell might make to Gulf Power due to unscheduled outages are determined on an annual basis in accordance with the terms of the contract. The multitude of variables on which these payments are dependent makes any attempt to provide a specific analysis for each year of the PPA term difficult to complete in a meaningful form.

The protections Gulf receives when Shell is unable to meet scheduled energy requests are detailed in Section 5.7 of the PPA. Shell could elect a Cover Payment, a Financial Settlement, or provide energy from an Alternate resource. Each of these options is designed to provide protection to Gulf and its customers in the event of an unscheduled outage. If Shell should choose not to select one of these options, the undelivered energy could have a negative impact on their Availability Factor which could result in a penalty paid by Shell to Gulf. This has the effect of reducing Shell's capacity payment. It is important to note that any of these options provides greater protection to customers than an outage event on a self owned plant. In the case of a forced outage event on a self owned plant, Gulf would either take energy from the SES pool or go to the market.

In developing the contract, Gulf was focused on ensuring the owner (Tenaska) had incentives to make the unit perform reliably, and for Gulf to be compensated if the unit does not perform reliably. Given the fact that determining the particular cost associated with unscheduled outages is very case specific based on many variables, Gulf evaluated scenarios in which the factors associated with the penalty payments each fall short of their respective target by one percent, and the Bonus Availability Factor exceeds its target by one percent. The conclusion of the unscheduled outage analysis was that the PPA does provide reasonable incentives to the Seller to make the unit perform reliably, and the contract does provide Gulf Power and its customers with an adequate level of protection.

30. Reference Article 10 of the PPA. What are the current S&P/Fitch and Moody's credit ratings for:
    a. Shell Energy North America (US), L.P.; and
    b. Gulf Power Company?

    Response:

	Gulf Power	Shell Energy North America (US), L.P.
S&P Credit Rating	A	A-
Fitch Credit Rating	A	no rating available
Moody's Credit Rating	A2	A2

31. Reference Article 10 of the PPA. If Shell were to default on the PPA for failure to deliver the expected capacity and energy, what would Gulf have to pay for replacement of that capacity and energy from another source during the following periods:
    a. Effective date through May 31, 2013;

       Response:

       In the event of a "default" by Shell, no further payments would be made by Gulf to Shell and Gulf would be entitled to actual damages from Shell as outlined in Article 11 of the PPA.

    b. June 1, 2013 through May 31, 2018;

       Response:

       In the event of a "default" by Shell, no further payments would be made by Gulf to Shell and Gulf would be entitled to actual damages from Shell as outlined in Article 11 of the PPA.

    c. June 1, 2019 through May 31, 2021; and

       Response:

In the event of a "default" by Shell, no further payments would be made by Gulf to Shell and Gulf would be entitled to actual damages from Shell as outlined in Article 11 of the PPA.

d. June 1, 2021 through May 31, 2023?

Response:

In the event of a "default" by Shell, no further payments would be made by Gulf to Shell and Gulf would be entitled to actual damages from Shell as outlined in Article 11 of the PPA.

32. Reference Table 10.1. Please explain the rationale for how the listed confidential amounts were determined.

Response:

The listed confidential amounts in Table 10.1 were set at a level that would provide a high degree of confidence that, in the event of a Default by the Seller (Shell), the Eligible Collateral posted by the Seller would cover the Buyer's (Gulf) damages. Article 11 of the PPA contains the provisions detailing how these damages (the Termination Payment) would be determined.

33. Reference PPA paragraphs 10.1 and 10.2. Please provide the following information about the Eligible Collateral Amount for each party, Gulf and Shell:

a. What is the form of asset being used as collateral, i.e. cash, bond, letter of credit, secured or unsecured note, etc.;

Response:

Eligible Collateral for either party may be in the form of (1) a Letter of Credit, (2) cash, or (3) a guaranty. Eligible Collateral is only required to be posted in the event a Rating Agency lowers Gulf's or Shell's Credit Rating to the applicable level specified in Table 10.1. Based on their current Credit Ratings, neither party is currently required to post Eligible Collateral

b. If a debt instrument, who is the lender, what are the terms, and when does the instrument mature?

Response:

A debt instrument is not an acceptable form of Eligible Collateral.

c. If a letter of credit, who is the issuing financial institution, and what is the collateral for the letter of credit?

<u>Response:</u>

The letter of credit would be issued by a financial institution meeting the criteria set forth in the purchased power agreement, which states that the issuer must be a U. S. commercial bank or a U. S. branch of a foreign bank that meets minimum asset and debt rating requirements. The collateral for the letter of credit would be a determined between the issuing financial institution and the party entering into the letter of credit.

d. Who will hold the Eligible Collateral Amounts provided by each party?

<u>Response:</u>

Gulf would hold the Eligible Collateral provided by Shell. Shell would hold the Eligible Collateral provided by Gulf. If the Eligible Collateral is in the form of cash, it would be deposited into a Gulf Power Security Account or a Shell Security Account, as the case may be. Definitions of these Security Accounts are found in Article 1.

34. Please answer the following general questions about the Tenaska generating plant:

a. Who previously purchased the capacity and energy from the Tenaska generating plant?

<u>Response:</u>

Shell entered into an agreement with Tenaska in 2000 to take the capacity and energy output of the Tenaska generating plant beginning in May 2003 when the unit went commercial. The Shell Tenaska agreement ends on May 24, 2023.

b. What was the duration of the last purchasing agreement?

<u>Response:</u>

See response to 34 a. above.

c. Why did the previous purchaser quit?

<u>Response:</u>

See response to 34 a. above.

d. Was Shell a part of the previous purchasing agreement?

<u>Response:</u>

See response to 34 a. above.

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

IN RE: Petition for Approval of Purchased Power Agreement between Gulf Power Company And Shell Energy North America (U.S.) LP Dated March 16, 2009.

Docket No.: 090169 - EI

CERTIFICATE OF SERVICE

I HEREBY CERTIFY that a true copy of the foregoing was furnished by U. S. mail this 12th of May, 2009, on the following:

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