BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

DOCKET NO. 090172-EI
FLORIDA POWER & LIGHT COMPANY

IN RE: FLORIDA POWER & LIGHT COMPANY'S PETITION TO DETERMINE NEED FOR FLORIDA ENERGYSECURE LINE

REBUTTAL TESTIMONY & EXHIBITS
OF

TIMOTHY C. SEXTON

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JULY 2, 2009

Q. Please state your name and business address.

A. My name is Timothy C. Sexton. I am Vice President of Gas Supply Consulting, Inc. My business address is 14811 St. Mary's, Suite 175, Houston, TX 77079.

Q. Did you previously submit direct testimony in this proceeding?

A. Yes.

Q. Are you sponsoring any rebuttal exhibits in this case?

A. Yes. I am sponsoring the following rebuttal exhibits:

- **TCS-8** Updated Gas Cost Savings Analysis
- **TCS-9** Illustrative Map of Pipeline Facilities
- **TCS-10** Capacity Holders on Pipelines Upstream of Transco Station 85
- **TCS-11** Marginal Cost to Transport to Transco Station 85
- **TCS-12** Capacity Holders on Southeast Supply Header
- **TCS-13** Total Cost to Transport from Perryville to FGT Mobile Bay Area

Q. What is the purpose of your rebuttal testimony?

A. The purpose of my rebuttal testimony is to comment on the testimony of Florida Gas Transmission Company, LLC ("FGT") witnesses Michael T. Langston and Benjamin Schlesinger. Specifically, I will address the following issues:

- Economic Analysis update incorporating FGT's March 18, 2009 proposal
- FPL's methodology for developing its long range forecast of natural gas prices
- Liquidity of Perryville Hub natural gas supplies available to FGT versus those available to Transco Station 85 and the Florida EnergySecure Line project; and
- Appropriate cost for FGT shippers to directly access supplies at Transco Station 85.

SUMMARY

Q. Please summarize your rebuttal testimony.

A. With respect to FGT's updated March 18, 2009 proposal, an Updated Gas Cost Savings Analysis reveals that the Florida EnergySecure Line project has superior economic results for FPL's customers when compared with the FGT (Company B) project alternative based upon FGT's proposal.

Next, as to the liquidity of supplies at Transco Station 85 versus supplies into FGT near Mobile Bay, it is an important fact that producers have made substantial investments over the past several years supporting the construction of pipelines to Transco Station 85. In contrast, these producers have not made these same investment decisions with respect to pipeline capacity from unconventional supply sources to FGT or Gulfstream near Mobile Bay. This allocation of investment dollars clearly indicates that producers have expressed a preference for making unconventional supplies available at Transco Station 85 versus making them available into FGT and/or Gulfstream near Mobile Bay.

With respect to capacity from Transco Station 85 to FGT near Mobile Bay, existing low-cost capacity is scarce and is not likely to be available to support FPL's Modernization projects. As a result, FPL appropriately utilized new construction costs as a proxy to develop a $0.20 per MMBtu rate applicable to transporting gas supplies from Transco Station 85 to the FGT/Company B project.

Finally, with respect to FPL's projection of fuel prices and with respect to futures prices and rates of escalation, the forecast relies upon third party projections from highly reputable sources and is a reasonable tool for planning purposes.

UPDATED GAS COST SAVINGS ANALYSES

Q On Pages 10 and 11 of his testimony, FGT witness Langston states that FGT provided an updated response to FPL's Solicitation on March 18, 2009. Witness Langston further states that FPL did not analyze the improved cost information included in this March 18, 2009 response. Did you include an analysis of the March 18, 2009 proposal in your Direct Testimony?

A. No I did not. The March 18, 2009 proposal received from FGT was the fourth proposal received by FPL from FGT and was received after my direct testimony and associated exhibits were substantially completed. As this proposal was unsolicited as well as the fourth response submitted by FGT, FPL had no way of knowing if additional unsolicited responses would be forthcoming from FGT prior to the date that the testimony was to be filed. As such, FPL made the decision to complete the testimony and exhibits as substantially drafted based upon the prior (January 12, 2009) proposal received from FGT. Consequently, prior to filing my direct testimony in this proceeding, I did not examine the March 18, 2009 proposal as a part of my direct testimony and it was not included in the Gas Cost Savings Analysis therein.

Q. Have you now developed an Updated Gas Cost Savings Analysis incorporating the March 18, 2009 proposal from FGT?

A. Yes. I have developed an Updated Gas Cost Savings Analysis incorporating the March 18, 2009 proposal from FGT. The detailed analysis is attached as Exhibit TCS-8.

Q. In addition to updating the analysis to incorporate FGT's March 18, 2009 proposal rather than the January 12, 2009 proposal, did you make any other adjustments in the Updated Gas Cost Savings Analysis versus the Gas Cost Savings Analysis filed with your Direct Testimony?

A. Yes. In order to account for changes in market conditions from the time of the evaluation presented in my direct testimony to the present time, I have made various other adjustments to the analysis including:

- As discussed in detail in the rebuttal testimony of FPL witness Enjamio, FPL has updated the revenue requirements associated with the Florida EnergySecure Line project to current market conditions. I have utilized these updated revenue requirements in my Updated Gas Cost Savings Analysis;
- As discussed in the rebuttal testimony of FPL witness Enjamio, the cost estimate and associated revenue requirements associated with the Florida EnergySecure Line project as well as the proposed rates for the Company E and FGT (formerly Company B) proposals have been adjusted to reflect current costs of steel. I have adopted these updated revenue requirements and rates in my updated Gas Cost Savings Analysis.
- In order to be consistent with the weighted average cost of capital in FPL's filed rate case; I utilized an updated discount rate of 8.89% to represent the discount rate applicable to FPL's customers in this analysis.

Q. Did you incorporate any assumptions with respect to the value of any excess pipeline capacity not utilized to support FPL demand requirements?

A. Yes. Consistent with my original Gas Cost Savings Analysis, I have included three revenue assumptions associated with off system capacity sales based upon capacity valuations consistent with those supporting the original Gas Cost Savings Analysis. As such, the Updated Gas Cost Savings Analysis identified as Case A incorporates an assumption that FPL receives revenues from the off system sale of excess capacity equal to the average value paid for capacity on the secondary market by FPL during 2008. The Updated Gas Cost Savings Analysis identified as Case B incorporates an assumption that FPL receives revenues associated with the off system sale of excess capacity equal to the maximum tariff rate associated with the transportation capacity in FPL's portfolio that has the highest corresponding tariff rate (FGT's proposed Phase VIII expansion maximum tariff recourse rate). Finally, as a worst case assumption, the Updated Gas Cost Savings Analysis identified as Case C incorporates an assumption that there is no revenue associated with the off system sale of excess capacity.

Q. Did the results of the Updated Gas Cost Savings Analysis favor the Florida EnergySecure Line or FGT's March 18, 2009 expansion proposal?

A. The results of the Updated Gas Cost Savings Analysis still favor the Florida EnergySecure Line alternative. These results are illustrated on Page 1 of Exhibit TCS-8.

Q. What were the results of the Updated Gas Cost Savings Analyses set forth in Exhibit TCS-8?

A. As depicted on Exhibit TCS-8, in all three cases the Updated Gas Cost Savings Analysis favors the Florida EnergySecure Line project alternative. In fact, the Net Present Value of savings utilizing the Florida EnergySecure Line project alternative versus the Company B alternative range from $123 million to $757 million.

Q. On Page 12 of his testimony, FGT witness Langston states that FGT's cost would have been reduced by an approximate $132 million if FGT had known of the availability of the FPL-owned dual-fuel pipeline from the Martin Plant to the 45th Street Terminal near the Riviera Plant. Do you agree with this statement?

A. No. As discussed in the rebuttal testimony of FPL witness Sharra, in order to utilize this existing pipeline to meet its needs at the Riviera Beach Energy Center (RBEC), FPL will have to incur approximately $86 million in capital cost to upgrade this pipeline system as necessary to make deliveries to the RBEC. Thus, FGT's projected $132 million savings associated with the use of this line would have to be reduced by the approximately $86 million upgrade cost in order to make an apples to apples comparison to the Florida EnergySecure Line project.

Q. Have you analyzed the economics of FGT's March 18, 2009 proposal taking into account both FGT's alleged costs savings and FPL's costs associated with potential use of the existing FPL-owned dual-fuel pipeline?

A. Yes. I conducted such an analysis using the same approach discussed in my direct testimony. Consistent with the results cited by FPL witness Enjamio in his rebuttal testimony, the results of my analysis continue to favor the Florida EnergySecure Line alternative versus the FGT proposed alternative.

NATURAL GAS PRICE FORECASTING METHODOLOGY

Q. Do you agree with FGT witness Schlesinger's assertion on Page 9 of his testimony that FPL's economic assumptions as to future gas supply prices are not reasonable for planning purposes?

A. No. I do not. As explained in detail in the rebuttal testimony of FPL witness Sharra, the economic assumptions utilized by FPL in developing forecasts of future gas supply prices were based upon market conditions at the time that the forecast was developed. Further, with respect to futures prices and rates of escalation, the forecast took into account third party projections from highly reputable sources (the PIRA Energy Group, the Energy Information Administration of the US Department of Energy and NYMEX forward price curves). As such, I believe that the forecast is reasonable for planning purposes in this proceeding.

LIQUIDITY AT FGT – MOBILE BAY AREA VERSUS TRANSCO STATION 85

Q. FGT witnesses Schlesinger and Langston assert in their testimony that FGT's proposal, with receipts in and around Mobile Bay is superior to the Florida EnergySecure Line/Company E project with receipts at Transco Station 85. Based upon this assertion, the FGT witnesses contend that FGT's system in the Mobile Bay area rather than FPL's selection of Transco Station 85 would be a superior location for the commencement of the proposed facilities. Do you agree with this contention?

A. No. I do not. In addition to providing a superior economic result for FPL's customers than the FGT proposal, the Florida EnergySecure Line project also meets FPL's goal of increasing supply diversity in its portfolio whereas the FGT proposal does not provide this diversification in the supply base.

As described in detail on Page 20 of my direct testimony, with the initiation of its capacity contract on FGT's Phase VIII project, approximately 1.4 Bcf/day of FPL's 2.0 Bcf/day of firm natural gas transportation capacity will be sourced from FGT and Gulfstream points in the Mobile Bay Area. Recognizing that traditional supply sources into the Mobile Bay area are in decline, FPL has been active in diversifying its supply sourcing in this area. In fact, FPL has entered into a capacity contract with Southeast Supply Header (SESH) providing for 0.5 Bcf/day of pipeline capacity from Perryville into its capacity on FGT and

Gulfstream. Further, FPL has been actively discussing potential additional capacity alternatives upstream of FGT and Gulfstream in support of both its existing capacity and its Phase VIII capacity rights.

With this said, as current transportation contracts will require FPL to source approximately 70% of its gas supplies in the Mobile Bay area (1.4 Bcf/day out of about 2.0 Bcf/day), sourcing additional supplies at this location via the FGT system would be contrary to FPL's goal of diversifying its natural gas supply portfolio. In contrast, sourcing incremental gas supply needs at the Transco Station 85 location will enable FPL to diversify its portfolio of natural gas supply beyond the current concentration in the Mobile Bay area.

Consequently, I believe that FPL has made the correct decision in targeting Transco Station 85 as the supply source to meet its incremental natural gas demand requirements.

Q. On Pages 25 and 26 of his direct testimony, FGT witness Langston states that "the market prices for gas at the Perryville Hub would provide better netbacks to producers as compared to the expected pricing at Transco Station 85." Witness Langston further states that "once all gas demand at this location is met, then gas would move to other markets, such as to planned interconnects at Transco Station 85." Do you agree with witness Langston's assertion that producers will have a preference to deliver gas to markets at the Perryville Hub versus delivering to Transco Station 85?

A. No. I do not. As mentioned on Pages 21 through 24 of my direct testimony, in the past year three new pipeline alternatives designed to transport unconventional supplies to the Perryville area and beyond to Transco Station 85 have been placed into service. These pipelines include the (i) MidContinent Express Pipeline (MEP); (ii) Gulf South East Texas to Mississippi and Southeast Expansion Projects and (iii) Gulf Crossing Pipeline which, utilizing Gulf Crossing's Capacity Lease on the Gulf South system, provides direct access to Transco Station 85. As an illustration of the location of these facilities, attached as Exhibit TCS-9 is a map depicting the locations of these pipelines to Transco Station 85 with respect to the Florida natural gas infrastructure.

It is important to note that the bulk of the new transportation capacity on these pipelines is held by natural gas producers and aggregators (collectively, I will refer to them as "producers") in the form of firm gas transportation agreements with primary delivery point rights to Transco Station 85. In fact, as illustrated in Exhibit TCS-10, about 2.5 Bcf/day of the approximate 3.0 Bcf/day of capacity on these three systems is held under firm transportation agreements by producers with primary delivery point rights to Transco near its Compressor Station 85. The simple fact that these producers have entered long term firm transportation contracts to transport unconventional supplies to Transco Station 85 indicates that these producers will be ready, willing and able to deliver and sell supplies to this location.

Q. Do you agree with FGT witness Langston's assertion on Pages 25 and 26 of his testimony that "given the transportation cost from the Perryville area to Transco Station 85, it appears that the market prices for gas at the Perryville Hub would provide better netbacks to producers as compared to the expected pricing at Transco Station 85"?

A. No. I do not. In his analysis, FGT witness Langston commits a basic error with respect to the treatment of sunk costs. That is, he includes the impact of sunk costs in his analysis of the netback value to producers of gas sold at the Perryville Hub versus gas sold at Transco Station 85. This assumption is not valid and sunk costs must be ignored in properly evaluating the marginal netback available to the producers associated with sales of gas at the Perryville Hub versus at Transco Station 85.

More specifically, the fixed reservation fee costs of the transportation capacity held by the producers from the unconventional supply sources to Transco Station 85 will be paid regardless of whether the producers utilize this capacity to move the unconventional supplies to Perryville or to the primary contract delivery point of Transco Station 85. As such, these fixed reservation fees are "sunk costs" and will typically be set aside by the producers in making comparisons of netback calculations for sales to a given location. In other words, if a producer is committed to paying a fixed reservation fee for pipeline capacity to Transco Station 85, that cost cannot be considered in a marginal netback analysis in determining the best location to sell gas.

If, as witness Langston claims on lines 15 to 18 of Page 25 of his testimony, the value of gas at Transco Station 85 carries a $0.0567 to $0.1067 per MMBtu premium over the value of gas at Perryville, even if this premium is not as large as the sunk cost of capacity, as long as this premium exceeds the marginal variable cost to access this market, the producer will still have a preference to sell the gas at Transco Station 85 rather than at Perryville to take advantage of this premium. To summarize, the producer will not forgo the incremental revenue associated with the higher value Transco Station 85 market simply because it is not sufficient to cover the sunk costs paid regardless of where the gas is sold.

Q. Have you developed a marginal netback analysis that can be utilized to illustrate the value to a producer holding capacity on the aforementioned three pipelines of selling gas supplies at Transco Station 85 versus doing so at Perryville?

A. Yes. I have. As discussed, the only costs relevant to a producer in determining the marginal netback value of gas sales to a given location are (a) the sales price of the gas and (b) the marginal costs incurred by the producer in accessing the given market. As illustrated in Exhibit TCS-11, the marginal cost difference to transport gas supplies from field area locations to Transco Station 85 versus to the Perryville Hub is only about $0.0122 per MMBtu on the MEP system, $0.0022 per MMBtu on the Gulf South System and $0.0518 per MMBtu on the Gulf Crossing system.

Next, on Page 25 of his testimony, FGT witness Langston states that basis swap prices indicate that the value of gas sold at Perryville over the next 42 month period is approximately $0.09 to $0.14 per MMBtu below the Henry Hub price whereas gas at Transco Station 85 during this timeframe is currently priced at approximately $0.0333 below the Henry Hub price. As such, per FGT witness Langston's testimony, the market value of gas at Perryville is approximately $0.0567 per MMBtu to $0.1067 per MMBtu below the market value for gas at Transco Station 85.

The following table illustrates the results of a simple netback analysis, as viewed from the producer's perspective based upon these price differentials and marginal cost difference to transport supplies to Perryville versus to Transco Station 85.

	MEP	**Gulf Crossing**	**Gulf South**
Basis to Perryville	($0.09) – ($0.14)	($0.09) – ($0.14)	($0.09) – ($0.14)
Basis to Transco St 85	($0.0333)	($0.0333)	($0.0333)
Incremental Value at 85	**($0.0567) – ($0.1067)**	**($0.0567) – ($0.1067)**	**($0.0567) – ($0.1067)**
Marginal Cost to St 85	$0.0122	$0.0518	$0.0022
Netback Premium at St 85	**$0.0445 - $0.0945**	**$0.0049 - $0.0549**	**$0.0545 - $0.1045**

As illustrated in the table, in every situation, when sunk costs are properly ignored in the netback analysis, the producers will obtain a netback premium by delivering to Transco Station 85 versus Perryville on these pipelines. As such, with marginal netbacks for shippers on the MEP, Gulf Crossing and Gulf South systems higher at Transco Station 85 than at Perryville, these producer shippers will have an economic incentive to sell supplies at Transco Station 85 before making sales into the Perryville Hub market.

Q. **On pages 26 and 27 of his testimony, FGT witness Langston concludes that access to the Perryville Hub via the existing FGT and Gulfstream systems will provide superior natural gas supply access to unconventional supply sources than the Florida Energy Secure Line project. Do you agree with this conclusion?**

A. No. I do not. As stated in FGT witness Langston's testimony, the FGT and Gulfstream pipeline systems can receive supplies from the Perryville Hub either (a) through SESH or (b) via the Gulf South capacity lease on the Destin Pipeline system. FGT witness Langston fails to provide the whole story however, with respect to the quantity of this capacity that is potentially available to serve FPL markets.

First, the Gulf South capacity lease is for a maximum capacity of only 260,000 MMBtu/day. Perhaps more importantly, while SESH has a maximum capacity of 1 Bcf/day, as illustrated in Exhibit TCS-12, approximately 90% of the capacity on SESH is under contract to end use markets with about 5% under contract to a producer and about 5% as of yet unsold. These end use capacity holders, such as FPL, have contracted for this capacity to serve their existing firm markets under peak day conditions. Thus, this capacity will not be available to provide supply to incremental FPL markets under peak day conditions. If one excludes this "end use held" SESH capacity from the total capacity available to deliver Perryville supplies to FGT and Gulfstream in the Mobile Bay area, a total of only about 360,000 MMBtu/day of capacity (260,000 MMBtu/day held by producers on Gulf South's capacity lease of Destin Pipeline, 50,000 MMBtu/day held by producers on SESH and 50,000 MMBtu/day unsold on SESH) is available to meet the demands of end use markets. In comparison to this total available capacity to access Perryville sources from FGT/Gulfstream near Mobile Bay of 360,000 MMBtu/day, the combined capacity available via the three pipeline routes to Transco Station 85 (MEP, Gulf Crossing and Boardwalk's Southeast Expansion) is approximately 3 Bcf/day with the vast majority of this capacity held by producer shippers.

It is also important to consider that, as pointed out in my direct testimony, FGT's Phase VIII project is designed to source an incremental 821,000 MMBtu/day from Mobile Bay area supply sources. In addition, Gulfstream's recent Phases 3 and 4 expansion projects also were designed to source supplies from the Mobile Bay Area. In the aggregate, after the installation of FGT's Phase VIII project, Gulfstream's and FGT's shippers will rely upon approximately 3.0 Bcf/day of receipts in and around the Mobile Bay Area.

Recognizing that traditional Mobile Bay supply sources are in decline coupled with the fact that FGT's Phase VIII shippers will need to obtain supplies in this same area sufficient to meet 821,000 MMBtu/day of incremental Phase VIII demand indicates that the 360,000 MMBtu/day of potentially available supplies on the SESH system and Gulf South's Destin leased capacity will likely be fully utilized prior to initiation of a proposed FGT/Company B project.

Consequently, it is clear that in the current environment, Transco Station 85 will provide FPL with superior access to Perryville supply sources to support future natural gas needs than will the FGT/Gulfstream pipelines sourcing gas from the Mobile Bay area.

Q. Do the investment decisions made by producers over the past several years provide any indication of the potential liquidity of Perryville supplies at Transco Station 85 versus at Mobile Bay via the FGT and/or Gulfstream Systems?

A. Yes. As mentioned previously in my rebuttal testimony, three new pipelines with a combined capacity of about 3 Bcf/day have recently been constructed from unconventional sources to the Transco Station 85 location. As also discussed, and as illustrated in Exhibit TCS-10, the capacity on these three pipelines is primarily held by producers with primary delivery point rights to the Transco Station 85 area. The simple fact that the producers have seen fit to make the substantial investment required, through the execution of long term capacity contracts, to support the construction of these pipelines from unconventional sources to Transco Station 85 provides a strong indication that these producers view the Transco Station 85 market as a desirable high value liquid market for unconventional supplies.

As a result of this view of the market at Transco Station 85, the producers have made the investment required to make 3 Bcf of unconventional supplies available at this location. This is not the case with respect to Mobile Bay. In contrast to Transco Station 85, the producers have not made substantial investments to transport unconventional supplies to FGT and Gulfstream in the Mobile Bay area. In fact, the one large scale pipeline that was built to transport unconventional supplies to the Mobile Bay area in the past few years, the SESH pipeline, was constructed based upon capacity contracts entered into primarily by the end use market, including FPL who was the anchor shipper for the SESH project. These investment decisions provide a clear indication that the producers view the Transco Station 85 market as a more liquid and desirable market than the FGT / Gulfstream market in and around Mobile Bay.

It is important to recognize that, in order to attract unconventional supplies to FGT and Gulfstream near Mobile Bay, the end use market has had to make substantial investments in upstream capacity whereas the producers have been willing to make the investments required to make these supplies available at Transco Station 85. In contrast to the producers willingness to make the investments required to make supplies available at Transco Station 85, past history suggests that if FPL were to contract for additional capacity on FGT with receipt point rights at Mobile Bay, it is very likely that FPL will be forced to make the incremental capacity investment required to solve supply issues at Mobile Bay.

Q. What impact would the apparent lack of available capacity between Perryville and the FGT system have on the price of incremental Perryville supplies delivered into FGT?

As stated previously, sufficient capacity does not appear to exist upstream of the FGT/Gulfstream systems to provide FPL with direct access to incremental supplies at the Perryville Hub via FGT. Thus, in order to obtain access to Perryville supplies via the existing FGT and/or Gulfstream systems, FPL would need to support an incremental pipeline expansion from Perryville to the FGT and/or Gulfstream systems.

Unlike the analysis developed above with respect to producer "sunk costs" associated with transportation capacity to Transco Station 85, costs associated with a new expansion from Perryville to FGT would require new capital investment that must be considered in the evaluation of the overall cost associated with the decision of whether or not to pursue such an expansion option.

Consequently, an analysis of the cost for FPL to obtain incremental gas supplies into the FGT system from Perryville would have to include the total all-in cost of expansion capacity from Perryville to FGT. These costs will include (a) the value of gas supplies at Perryville; (b) fixed costs associated with incremental capacity contracts; and (c) variable costs associated with the incremental capacity.

In discussions concerning possible future expansion opportunities, as described in FPL witness Sharra's rebuttal testimony, SESH representatives have provided indications to FPL that future expansion rates would be higher in cost than the transportation rates paid by FPL for its existing SESH capacity. With this said, in order to be conservative in assumptions, the evaluation includes potential fixed and variable costs of capacity from Perryville to FGT based upon FPL's current SESH negotiated rate agreement cost structure.

As illustrated in Exhibit TCS-13, the total transportation costs (fixed plus variable) to transport gas supplies from Perryville to FGT is approximately $0.34 per MMBtu. Thus, adding this transport cost to FGT witness Langston's quoted market value of gas at Perryville of Henry Hub less $0.09 to $0.14 per MMBtu reveals that the projected "all-in" delivered cost of this supply into FGT near Mobile Bay would be approximately $0.20 to $0.25 per MMBtu above Henry Hub prices.

As mentioned previously, the current market for gas supplies at Transco Station 85 is approximately $0.0333 below the Henry Hub price reflecting an approximate $0.23 to $0.28 per MMBtu discount versus the all in costs to obtain Perryville supplies via upstream expansions to FGT. Consequently, it is clear that in analyzing incremental supply requirements, the Transco Station 85 location will provide superior access to Perryville Hub supplies at lower delivered costs than access to Perryville supplies via the FGT system.

APPROPRIATE COST TO PROVIDE FGT SYSTEM WITH DIRECT ACCESS TO SUPPLIES AT TRANSCO STATION 85

Q. FGT witness Schlesinger on Page 15 of his direct testimony and FGT witness Langston on Pages 20 and 21 of his direct testimony reference capacity made available via an open season solicitation by Transco from Transco Station 85 to FGT and/or Gulfstream at a current tariff recourse rate of approximately $0.09 per MMBtu. Is this $0.09 per MMBtu rate quoted by the witnesses a predetermined fixed rate?

A. No. With respect to rates in its open season process, Transco did not provide a guarantee that the ultimate contract rate would be $0.09 per MMBtu. Rather, the language in the open season documents (documents attached as Exhibit BSA-4 to FGT witness Schlesinger's testimony) was as follows:

> "the maximum rates applicable to the Expansion will be the maximum daily firm reservation and commodity rate under Rate Schedule FT for Zone 4A to 4A transportation, as such rates may change from time to time. However, if the calculated maximum rates for the Expansion, based on the final design and cost of the Expansion facilities, exceed the maximum rates for Zone 4A to 4A transportation under Rate Schedule FT, then the maximum rates will be based on the incremental cost of the Expansion"

Thus, as outlined in Transco's open season documents, there is no certainty as to a fixed $0.09 per MMBtu rate referenced in the FGT witness testimonies. Rather, statements are made in Transco's open season documents that the capacity will be sold at the maximum tariff rate *as such rate may change from time to time,* and that if *final design and cost of the Expansion exceeds the maximum tariff rate for this haul, then the maximum rates will be based upon the incremental cost of the*

Expansion (emphasis added). As such, there is no certainty that the ultimate rate for this capacity will be the current tariff rate of $0.09 per MMBtu.

Q. Is the capacity on Transco's system from Transco Station 85 to FGT and Gulfstream (quoted by FGT witnesses Langston and Schlesinger as $0.09 per MMBtu capacity) likely to be available to serve the FPL Modernizations?

A. No. Perhaps more important than the rate uncertainty associated with this capacity, as noted in the rebuttal testimony of FPL witness Sharra, as a result of the recent Transco open season, Transco has indicated that they have interested parties in negotiations for the remaining 550,000 MMBtu per day of capacity on this line. As such, the existing lateral capacity likely will not be available to serve the Modernization Projects.

Q. Do you believe that the $0.20 per MMBtu rate that you developed as a proxy to represent the cost to transport gas from Transco Station 85 to FGT near Mobile Bay in your direct testimony is still appropriate?

A. Yes. In light of the fact that the Transco capacity is likely to be fully subscribed as a result of its open season process, any new capacity from Transco Station 85 to FGT used to serve FPL's Modernization Projects will likely be priced based upon the cost to install new facilities required to transport this gas. As such, the $0.20 per MMBtu rate, developed based upon the cost of new facilities from Transco Station 85 to FGT near Mobile Bay remains an appropriate proxy to represent the cost to transport gas from Transco Station 85 to FGT near Mobile Bay.

Q. Does this conclude your rebuttal testimony?

A. Yes.

Life Cycle Net Savings of Upstream Pipeline Project / Florida EnergySecure Line Project vs. Company B Proposal

Case	Excess Capacity Value Assumptions	Net Savings ($MM)	NPV of Savings at 8.89% Discount Factor ($MM)
Case A	(a) Excess capacity sold at current market values for secondary capacity. (b) Underutilized capacity economically dispatched by FPL to FPL Plants.	$7,484	$298
Case B	(a) Excess capacity sold at FGT Proposed Phase VIII Project Recourse Rate. (b) Underutilized capacity economically dispatched by FPL to FPL Plants.	$8,644	$757
Case C	(a) Excess capacity retained by FPL. (b) Excess and Underutilized capacity economicallly dispatched by FPL to FPL Plants.	$6,672	$123

Summary Comparative Cost Analysis

Case A - Excess Capacity Valued at 2008 Market Value

Year	Company B Proposal				Upstream Pipeline Project - Florida EnergySecure Line Project 1/							
	Demand Charges to Company B ($/Year)	Annual Cost of Fuel Retention Gas ($/Year)	Value of Capacity Release Credits ($/Year)	Net Gas Transport Costs ($/Year)	Demand Charges on Upstream Pipeline Project ($/Year)	Annual Florida EnergySecure Line Revenue Requirements ($/Year)	Annual Cost of Fuel Gas Retained / Consumed ($/Year)	Upstream Pipeline Project Commodity Charges ($/Year)	Value of Capacity Release Credits ($/Year)	Net Gas Transport Costs ($/Year)	Potential Savings Associated with Economic Dispatch Activity ($/Year)	Florida Energy Secure Line vs. Company B Net Savings ($/Year)
Column	1	2	3	4	5	6	7	8	9	10	11	12
Source	Attachment I	Attachment II, Col 14	Attachment VB, Col 5	Column 1 + Column 2 + Column 3	Attachment IIB	Attachment IIA, Column 5	Attachment IV, Col 13	Attachment IV, Col 16	Attachment VA, Col 5	Sum of Columns 5 through 9	Attachment VI A, Col 15	Column 4 - Column 10 + Column 11
2012	$ 9,824,700	$ -	($2,385,639)	$ 7,539,061	[redacted]	$429,102	[redacted]	[redacted]	$0	[redacted]	$ -	[redacted]
2013	$ 109,254,548	$ 10,111,184	($11,374,487)	$ 107,991,245	[redacted]	$21,083,575	[redacted]	[redacted]	$0	[redacted]	$ -	[redacted]
2014	$ 267,725,998	$ 27,496,720	($37,787,231)	$ 257,435,487	[redacted]	$290,851,119	[redacted]	[redacted]	($44,124,646)	[redacted]	$ 5,828,276	[redacted]
2015	$ 267,725,998	$ 35,646,968	$0	$ 303,372,967	[redacted]	$280,758,254	[redacted]	[redacted]	($33,957,721)	[redacted]	$ 4,133,139	[redacted]
2016	$ 268,459,494	$ 39,853,091	$0	$ 308,312,585	[redacted]	$259,256,843	[redacted]	[redacted]	($34,902,024)	[redacted]	$ 3,678,787	[redacted]
2017	$ 267,725,998	$ 43,404,627	$0	$ 311,130,825	[redacted]	$256,489,524	[redacted]	[redacted]	($35,676,830)	[redacted]	$ 3,492,079	[redacted]
2018	$ 267,725,998	$ 47,357,421	$0	$ 315,093,419	[redacted]	$246,394,987	[redacted]	[redacted]	($36,568,751)	[redacted]	$ 3,539,804	[redacted]
2019	$ 267,725,998	$ 51,136,030	$0	$ 318,862,028	[redacted]	$236,902,662	[redacted]	[redacted]	($37,482,970)	[redacted]	$ 3,941,587	[redacted]
2020	$ 268,459,494	$ 52,543,249	$0	$ 321,002,744	[redacted]	$229,833,207	[redacted]	[redacted]	($38,525,305)	[redacted]	$ 4,533,935	[redacted]
2021	$ 338,114,604	$ 64,100,375	$0	$ 402,214,978	[redacted]	$220,904,087	[redacted]	[redacted]	($21,864,117)	[redacted]	$ 5,656,337	[redacted]
2022	$ 410,262,924	$ 77,111,429	$0	$ 487,374,353	[redacted]	$211,976,818	[redacted]	[redacted]	($4,458,380)	[redacted]	$ 6,986,102	[redacted]
2023	$ 658,166,981	$ 102,583,566	$0	$ 660,750,547	[redacted]	$226,023,862	[redacted]	[redacted]	($10,516,113)	[redacted]	$ 5,563,921	[redacted]
2024	$ 635,704,708	$ 117,153,656	$0	$ 752,858,364	[redacted]	$232,285,452	[redacted]	[redacted]	($35,127,779)	[redacted]	$ 4,820,803	[redacted]
2025	$ 789,359,510	$ 144,060,449	$0	$ 933,419,959	[redacted]	$277,501,341	[redacted]	[redacted]	($52,480,334)	[redacted]	$ -	[redacted]
2026	$ 948,636,002	$ 172,326,039	$0	$1,120,962,041	[redacted]	$265,285,970	[redacted]	[redacted]	($14,155,679)	[redacted]	$ -	[redacted]
2027	$ 948,636,002	$ 175,759,610	$0	$1,124,395,611	[redacted]	$252,555,491	[redacted]	[redacted]	($14,509,776)	[redacted]	$ -	[redacted]
2028	$ 951,235,004	$ 179,752,972	$0	$1,130,987,977	[redacted]	$240,883,888	[redacted]	[redacted]	($14,913,268)	[redacted]	$ -	[redacted]
2029	$ 948,636,002	$ 182,834,115	$0	$1,131,470,118	[redacted]	$229,952,833	[redacted]	[redacted]	($15,244,334)	[redacted]	$ -	[redacted]
2030	$ 948,636,002	$ 186,477,823	$0	$1,135,113,825	[redacted]	$221,798,541	[redacted]	[redacted]	($16,625,442)	[redacted]	$ -	[redacted]
2031	$ 948,636,002	$ 190,194,397	$0	$1,138,830,399	[redacted]	$214,923,391	[redacted]	[redacted]	($16,016,079)	[redacted]	$ -	[redacted]
2032	$ 951,235,004	$ 194,516,781	$0	$1,145,751,785	[redacted]	$208,081,806	[redacted]	[redacted]	($16,461,457)	[redacted]	$ -	[redacted]
2033	$ 948,636,002	$ 197,852,001	$0	$1,146,488,003	[redacted]	$201,221,093	[redacted]	[redacted]	($16,828,892)	[redacted]	$ -	[redacted]
2034	$ 948,636,002	$ 201,796,033	$0	$1,150,432,035	[redacted]	$194,402,096	[redacted]	[redacted]	($17,247,565)	[redacted]	$ -	[redacted]
2035	$ 948,636,002	$ 205,818,937	$0	$1,154,454,939	[redacted]	$187,590,270	[redacted]	[redacted]	($17,678,754)	[redacted]	$ -	[redacted]
2036	$ 951,235,004	$ 210,497,420	$0	$1,161,732,424	[redacted]	$180,813,806	[redacted]	[redacted]	($18,170,388)	[redacted]	$ -	[redacted]
2037	$ 948,636,002	$ 214,107,701	$0	$1,162,743,703	[redacted]	$174,002,391	[redacted]	[redacted]	($18,573,741)	[redacted]	$ -	[redacted]
2038	$ 948,636,002	$ 218,376,811	$0	$1,167,012,812	[redacted]	$167,305,670	[redacted]	[redacted]	($19,038,084)	[redacted]	$ -	[redacted]
2039	$ 948,636,002	$ 222,731,293	$0	$1,171,367,294	[redacted]	$160,868,941	[redacted]	[redacted]	($19,514,036)	[redacted]	$ -	[redacted]
2040	$ 951,235,004	$ 227,795,246	$0	$1,179,030,251	[redacted]	$154,693,978	[redacted]	[redacted]	($20,058,687)	[redacted]	$ -	[redacted]
2041	$ 948,636,002	$ 231,703,238	$0	$1,180,339,240	[redacted]	$149,455,418	[redacted]	[redacted]	($20,501,934)	[redacted]	$ -	[redacted]
2042	$ 948,636,002	$ 236,324,219	$0	$1,184,960,221	[redacted]	$144,257,250	[redacted]	[redacted]	($21,014,483)	[redacted]	$ -	[redacted]
2043	$ 948,636,002	$ 241,037,609	$0	$1,189,673,611	[redacted]	$139,068,151	[redacted]	[redacted]	($21,539,845)	[redacted]	$ -	[redacted]
2044	$ 951,235,004	$ 246,518,805	$0	$1,197,753,809	[redacted]	$133,888,349	[redacted]	[redacted]	($22,138,829)	[redacted]	$ -	[redacted]
2045	$ 948,636,002	$ 250,749,045	$0	$1,199,385,047	[redacted]	$128,728,150	[redacted]	[redacted]	($22,630,298)	[redacted]	$ -	[redacted]
2046	$ 948,636,002	$ 255,750,899	$0	$1,204,386,901	[redacted]	$124,268,112	[redacted]	[redacted]	($23,196,057)	[redacted]	$ -	[redacted]
2047	$ 948,636,002	$ 260,852,779	$0	$1,209,488,781	[redacted]	$119,614,090	[redacted]	[redacted]	($23,775,958)	[redacted]	$ -	[redacted]
2048	$ 951,235,004	$ 266,785,608	$0	$1,218,020,612	[redacted]	$115,372,335	[redacted]	[redacted]	($24,437,125)	[redacted]	$ -	[redacted]
2049	$ 948,636,002	$ 271,364,658	$0	$1,220,000,659	[redacted]	$110,941,107	[redacted]	[redacted]	($24,979,618)	[redacted]	$ -	[redacted]
2050	$ 948,636,002	$ 276,778,777	$0	$1,225,414,779	[redacted]	$106,520,670	[redacted]	[redacted]	($25,604,107)	[redacted]	$ -	[redacted]
2051	$ 948,636,002	$ 282,301,168	$0	$1,230,937,169	[redacted]	$101,735,820	[redacted]	[redacted]	($26,244,209)	[redacted]	$ -	[redacted]
2052	$ 951,235,004	$ 288,722,853	$0	$1,239,957,858	[redacted]	$96,952,924	[redacted]	[redacted]	($26,974,014)	[redacted]	$ -	[redacted]
2053	$ 948,636,002	$ 293,679,462	$0	$1,242,315,464	[redacted]	$91,510,109	[redacted]	[redacted]	($27,572,822)	[redacted]	$ -	[redacted]
						Upstream Pipeline Project / Florida Energy Secure line vs. Company B Net Savings						$ 7,484,012,542
						Upstream Pipeline Project / Florida Energy Secure line vs. Company B (@2012) 8.59% NPV Savings						$ 298,451,858

1/ As the Florida EnergySecure Line Project and the Upstream Pipeline project are not projected to be in service prior to January 2014, costs for this option in 2012 and 2013 represent short-term workaround costs required to enable testing and initial usage of the CCEC and RBEC during these years. It is assumed that these initial needs would be served via a combination of (a) re-allocation of firm transportation entitlement rights on FGT (b) acquisition of secondary market capacity and (c) the installation of onsite compression at the CCEC and RBEC as required to increase pressure of delivered gas on FGT to required levels. The RBEC compression costs are embedded in overall Energy Secure Line project estimate and the CCEC on-site compression cost is added as a stand alone incremental revenue requirement (as estimated by FPL). In addition, as a conservative assumption, it is assumed that secondary capacity required during these years is consistent with quantities purchased from Company B under the Company B alternative and is purchased at market values (same value as release capacity is presumed sold). Finally, transportation fuel and usage costs are assumed identical to those with Company B service as the gas would be delivered via Company B during these years with this alternative.

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Updated Gas Cost Savings Analysis
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Summary Comparative Cost Analysis

Case B - Excess Capacity Valued at FGT Phase VIII Maximum Tariff Rate

Year	Company B Proposal: Demand Charges to Company B ($/Year)	Company B Proposal: Annual Cost of Fuel Retention Gas ($/Year)	Company B Proposal: Value of Capacity Release Credits ($/Year)	Company B Proposal: Net Gas Transport Costs ($/Year)	Upstream Pipeline Project - Florida EnergySecure Line Project 1/: Demand Charges on Upstream Pipeline Project ($/Year)	Annual Florida EnergySecure Line Revenue Requirements ($/Year)	Annual Cost of Fuel Gas Retained / Consumed ($/Year)	Upstream Pipeline Project Commodity Charges ($/Year)	Value of Capacity Release Credits ($/Year)	Net Gas Transport Costs ($/Year)	Potential Savings Associated with Economic Dispatch Activity ($/Year)	Florida Energy Secure Line vs. Company B Net Savings ($/Year)
Column	1	2	3	4	5	6	7	8	9	10	11	12
Source	Attachment I	Attachment II, Col 14	Attachment VB, Col 7	Column 1 + Column 2 + Column 3	Attachment IIIB	Attachment IIIA, Column 9	Attachment IV, Col 13	Attachment IV, Col 16	Attachment VA, Col 7	Sum of Columns 5 through 9	Attachment VI A, Col 15	Column 4 - Column 10 + Column 11
2012	$ 9,924,700	$ -	($8,198,069)	$ 1,726,631	[redacted]	$1,474,701	[redacted]	[redacted]	$0	[redacted]	$ -	[redacted]
2013	$ 109,254,548	$ 10,111,164	($39,087,505)	$ 80,278,207	[redacted]	$81,895,885	[redacted]	[redacted]	$0	[redacted]	$ -	[redacted]
2014	$ 267,725,998	$ 27,496,720	($37,787,231)	$ 257,435,487	[redacted]	$290,851,119	[redacted]	[redacted]	($151,643,803)	[redacted]	$ 5,828,278	[redacted]
2015	$ 267,725,998	$ 35,646,988	$0	$ 303,372,987	[redacted]	$280,769,254	[redacted]	[redacted]	($113,856,572)	[redacted]	$ 4,133,139	[redacted]
2016	$ 268,459,494	$ 39,853,091	$0	$ 308,312,585	[redacted]	$269,256,843	[redacted]	[redacted]	($114,168,508)	[redacted]	$ 3,676,767	[redacted]
2017	$ 267,725,998	$ 43,404,527	$0	$ 311,130,525	[redacted]	$258,489,524	[redacted]	[redacted]	($113,856,572)	[redacted]	$ 3,482,079	[redacted]
2018	$ 267,725,998	$ 47,367,421	$0	$ 315,093,419	[redacted]	$248,394,987	[redacted]	[redacted]	($113,856,572)	[redacted]	$ 3,539,604	[redacted]
2019	$ 267,725,998	$ 51,136,030	$0	$ 318,862,028	[redacted]	$238,902,682	[redacted]	[redacted]	($113,856,572)	[redacted]	$ 3,941,567	[redacted]
2020	$ 268,459,494	$ 52,543,249	$0	$ 321,002,744	[redacted]	$229,833,207	[redacted]	[redacted]	($114,158,508)	[redacted]	$ 4,533,935	[redacted]
2021	$ 338,114,604	$ 64,100,375	$0	$ 402,214,978	[redacted]	$220,904,087	[redacted]	[redacted]	($63,213,278)	[redacted]	$ 5,856,337	[redacted]
2022	$ 410,262,924	$ 77,111,429	$0	$ 487,374,353	[redacted]	$211,978,818	[redacted]	[redacted]	($12,569,984)	[redacted]	$ 6,986,102	[redacted]
2023	$ 558,156,981	$ 102,583,566	$0	$ 660,750,547	[redacted]	$226,023,862	[redacted]	[redacted]	($28,936,025)	[redacted]	$ 5,583,921	[redacted]
2024	$ 635,704,708	$ 117,153,656	$0	$ 752,858,364	[redacted]	$232,286,452	[redacted]	[redacted]	($54,309,506)	[redacted]	$ 4,820,803	[redacted]
2025	$ 789,359,510	$ 144,060,449	$0	$ 933,419,959	[redacted]	$277,501,341	[redacted]	[redacted]	($137,460,369)	[redacted]	$ -	[redacted]
2026	$ 948,636,002	$ 172,326,039	$0	$1,120,962,041	[redacted]	$265,265,970	[redacted]	[redacted]	($36,173,781)	[redacted]	$ -	[redacted]
2027	$ 948,636,002	$ 175,759,610	$0	$1,124,395,611	[redacted]	$252,655,491	[redacted]	[redacted]	($36,173,781)	[redacted]	$ -	[redacted]
2028	$ 951,235,004	$ 179,752,972	$0	$1,130,987,977	[redacted]	$240,583,566	[redacted]	[redacted]	($36,272,888)	[redacted]	$ -	[redacted]
2029	$ 948,636,002	$ 182,834,115	$0	$1,131,470,118	[redacted]	$229,952,833	[redacted]	[redacted]	($36,173,781)	[redacted]	$ -	[redacted]
2030	$ 948,636,002	$ 186,477,823	$0	$1,135,113,825	[redacted]	$221,796,541	[redacted]	[redacted]	($36,173,781)	[redacted]	$ -	[redacted]
2031	$ 948,636,002	$ 190,194,397	$0	$1,138,830,399	[redacted]	$214,923,391	[redacted]	[redacted]	($36,173,781)	[redacted]	$ -	[redacted]
2032	$ 951,235,004	$ 194,516,761	$0	$1,145,751,765	[redacted]	$208,081,606	[redacted]	[redacted]	($36,272,888)	[redacted]	$ -	[redacted]
2033	$ 948,636,002	$ 197,852,001	$0	$1,146,488,003	[redacted]	$201,221,093	[redacted]	[redacted]	($36,173,781)	[redacted]	$ -	[redacted]
2034	$ 948,636,002	$ 201,796,033	$0	$1,150,432,035	[redacted]	$194,402,098	[redacted]	[redacted]	($36,173,781)	[redacted]	$ -	[redacted]
2035	$ 948,636,002	$ 205,818,937	$0	$1,154,454,939	[redacted]	$187,590,270	[redacted]	[redacted]	($36,173,781)	[redacted]	$ -	[redacted]
2036	$ 951,235,004	$ 210,497,420	$0	$1,161,732,424	[redacted]	$180,813,808	[redacted]	[redacted]	($36,272,888)	[redacted]	$ -	[redacted]
2037	$ 948,636,002	$ 214,107,701	$0	$1,162,743,703	[redacted]	$174,002,391	[redacted]	[redacted]	($36,173,781)	[redacted]	$ -	[redacted]
2038	$ 948,636,002	$ 218,376,611	$0	$1,167,012,612	[redacted]	$167,305,670	[redacted]	[redacted]	($36,173,781)	[redacted]	$ -	[redacted]
2039	$ 948,636,002	$ 222,731,293	$0	$1,171,367,294	[redacted]	$160,968,941	[redacted]	[redacted]	($36,173,781)	[redacted]	$ -	[redacted]
2040	$ 951,235,004	$ 227,795,248	$0	$1,179,030,251	[redacted]	$154,893,976	[redacted]	[redacted]	($36,272,888)	[redacted]	$ -	[redacted]
2041	$ 948,636,002	$ 231,703,236	$0	$1,180,339,240	[redacted]	$148,455,418	[redacted]	[redacted]	($36,173,781)	[redacted]	$ -	[redacted]
2042	$ 948,636,002	$ 236,324,219	$0	$1,184,960,221	[redacted]	$144,257,250	[redacted]	[redacted]	($36,173,781)	[redacted]	$ -	[redacted]
2043	$ 948,636,002	$ 241,037,609	$0	$1,189,673,611	[redacted]	$139,068,151	[redacted]	[redacted]	($36,173,781)	[redacted]	$ -	[redacted]
2044	$ 951,235,004	$ 246,518,805	$0	$1,197,753,809	[redacted]	$133,888,349	[redacted]	[redacted]	($36,272,888)	[redacted]	$ -	[redacted]
2045	$ 948,636,002	$ 250,749,045	$0	$1,199,385,047	[redacted]	$128,728,150	[redacted]	[redacted]	($36,173,781)	[redacted]	$ -	[redacted]
2046	$ 948,636,002	$ 255,750,899	$0	$1,204,386,901	[redacted]	$124,266,112	[redacted]	[redacted]	($36,173,781)	[redacted]	$ -	[redacted]
2047	$ 948,636,002	$ 260,852,779	$0	$1,209,488,781	[redacted]	$119,614,090	[redacted]	[redacted]	($36,173,781)	[redacted]	$ -	[redacted]
2048	$ 951,235,004	$ 266,785,606	$0	$1,218,020,612	[redacted]	$115,372,335	[redacted]	[redacted]	($36,272,888)	[redacted]	$ -	[redacted]
2049	$ 948,636,002	$ 271,364,656	$0	$1,220,000,659	[redacted]	$110,941,107	[redacted]	[redacted]	($36,173,781)	[redacted]	$ -	[redacted]
2050	$ 948,636,002	$ 276,778,777	$0	$1,225,414,779	[redacted]	$106,520,670	[redacted]	[redacted]	($36,173,781)	[redacted]	$ -	[redacted]
2051	$ 948,636,002	$ 282,301,168	$0	$1,230,937,169	[redacted]	$101,735,820	[redacted]	[redacted]	($36,173,781)	[redacted]	$ -	[redacted]
2052	$ 951,235,004	$ 288,722,853	$0	$1,239,957,858	[redacted]	$96,952,924	[redacted]	[redacted]	($36,272,888)	[redacted]	$ -	[redacted]
2053	$ 948,636,002	$ 293,679,462	$0	$1,242,315,464	[redacted]	$91,510,109	[redacted]	[redacted]	($36,173,781)	[redacted]	$ -	[redacted]
						Upstream Pipeline Project / Florida Energy Secure line vs. Company B Net Savings						$ 6,543,763,642
						Upstream Pipeline Project / Florida Energy Secure line vs. Company B (@2012) 8.89% NPV Savings						$ 756,762,464

1/ As the Florida EnergySecure Line Project and the Upstream Pipeline project are not projected to be in service prior to January 2014, costs for this option in 2012 and 2013 represent short-term workaround costs required to enable testing and initial usage of the CCEC and RBEC during these years. It is assumed that these initial needs would be served via a combination of (a) re-allocation of firm transportation entitlement rights on FGT (b) acquisition of secondary market capacity and (c) the installation of onsite compression at the CCEC and RBEC as required to increase pressure of delivered gas on FGT to required levels. The RBEC compression costs are embedded in overall Energy Secure Line project estimate and the CCEC on-site compression cost is added as a stand alone incremental revenue requirement (as estimated by FPL). In addition, as a conservative assumption, it is assumed that secondary capacity required during these years is consistent with quantities purchased from Company B under the Company B alternative and is purchased at market values (same value as release capacity is presumed sold). Finally, transportation fuel and usage costs are assumed identical to those with Company B service as the gas would be delivered via Company B during these years with this alternative.

Summary Comparative Cost Analysis

Case C - Excess Capacity Given No Value in Marketplace

Year	Company B Proposal: Demand Charges to Company B ($/Year)	Company B Proposal: Annual Cost of Fuel Retention Gas ($/Year)	Company B Proposal: Value of Capacity Release Credits ($/Year)	Company B Proposal: Net Gas Transport Costs ($/Year)	Upstream Pipeline Project - Florida EnergySecure Line Project 1/: Demand Charges on Upstream Pipeline Project ($/Year)	Annual Florida EnergySecure Line Revenue Requirements ($/Year)	Annual Cost of Fuel Gas Retained / Consumed ($/Year)	Upstream Pipeline Project Commodity Charges ($/Year)	Value of Capacity Release Credits ($/Year)	Net Gas Transport Costs ($/Year)	Potential Savings Associated with Economic Dispatch Activity ($/Year)	Florida Energy Secure Line vs. Company B Net Savings ($/Year)
Column	1	2	3	4	5	6	7	8	9	10	11	12
Source	Attachment I	Attachment II, Col 14	Attachment VB, Col 9	Column 1 + Column 2 + Column 3	Attachment III	Attachment IIIA, Column 14	Attachment IV, Col 13	Attachment IV, Col 16	Attachment VA, Col 9	Sum of Columns 5 through 9	Attachment VI B, Col 16	Column 3 - (Column 10 - Column 11)
2012	$ 9,924,700	$ -	$0	$ 9,924,700	[redacted]	$0	[redacted]		$0	[redacted]	$ -	[redacted]
2013	$ 109,254,548	$ 10,111,164	$0	$ 119,365,712	[redacted]	$4,334,755	[redacted]		$0	[redacted]	$ -	[redacted]
2014	$ 267,725,998	$ 27,496,720	$0	$ 295,222,718	[redacted]	$290,851,119	[redacted]		$0	[redacted]	$ 15,029,184	[redacted]
2015	$ 267,725,998	$ 35,646,988	$0	$ 303,372,987	[redacted]	$280,769,254	[redacted]		$0	[redacted]	$ 11,328,875	[redacted]
2016	$ 268,459,494	$ 39,853,091	$0	$ 308,312,585	[redacted]	$269,256,843	[redacted]		$0	[redacted]	$ 11,178,973	[redacted]
2017	$ 267,725,998	$ 43,404,627	$0	$ 311,130,625	[redacted]	$258,489,524	[redacted]		$0	[redacted]	$ 11,328,223	[redacted]
2018	$ 267,725,998	$ 47,367,421	$0	$ 315,093,419	[redacted]	$248,394,987	[redacted]		$0	[redacted]	$ 11,858,681	[redacted]
2019	$ 267,725,998	$ 51,136,030	$0	$ 318,862,028	[redacted]	$238,802,662	[redacted]		$0	[redacted]	$ 12,902,034	[redacted]
2020	$ 268,459,494	$ 52,543,249	$0	$ 321,002,744	[redacted]	$229,833,207	[redacted]		$0	[redacted]	$ 13,908,369	[redacted]
2021	$ 338,114,604	$ 64,100,375	$0	$ 402,214,978	[redacted]	$220,904,067	[redacted]		$0	[redacted]	$ 11,104,481	[redacted]
2022	$ 410,262,924	$ 77,111,429	$0	$ 487,374,353	[redacted]	$211,978,618	[redacted]		$0	[redacted]	$ 8,041,577	[redacted]
2023	$ 558,166,981	$ 102,583,566	$0	$ 660,750,547	[redacted]	$226,023,862	[redacted]		$0	[redacted]	$ 7,072,966	[redacted]
2024	$ 635,704,708	$ 117,163,656	$0	$ 752,868,364	[redacted]	$232,285,452	[redacted]		$0	[redacted]	$ 8,562,322	[redacted]
2025	$ 789,359,510	$ 144,060,449	$0	$ 933,419,959	[redacted]	$277,501,341	[redacted]		$0	[redacted]	$ -	[redacted]
2026	$ 948,636,002	$ 172,326,039	$0	$1,120,962,041	[redacted]	$285,265,970	[redacted]		$0	[redacted]	$ -	[redacted]
2027	$ 948,636,002	$ 175,759,610	$0	$1,124,395,611	[redacted]	$252,656,491	[redacted]		$0	[redacted]	$ -	[redacted]
2028	$ 951,235,004	$ 179,752,972	$0	$1,130,987,977	[redacted]	$240,683,566	[redacted]		$0	[redacted]	$ -	[redacted]
2029	$ 948,636,002	$ 182,834,115	$0	$1,131,470,118	[redacted]	$229,952,633	[redacted]		$0	[redacted]	$ -	[redacted]
2030	$ 948,636,002	$ 186,477,823	$0	$1,135,113,825	[redacted]	$221,798,541	[redacted]		$0	[redacted]	$ -	[redacted]
2031	$ 948,636,002	$ 190,194,397	$0	$1,138,830,399	[redacted]	$214,923,391	[redacted]		$0	[redacted]	$ -	[redacted]
2032	$ 951,235,004	$ 194,516,761	$0	$1,145,751,765	[redacted]	$208,061,606	[redacted]		$0	[redacted]	$ -	[redacted]
2033	$ 948,636,002	$ 197,852,001	$0	$1,146,488,003	[redacted]	$201,221,093	[redacted]		$0	[redacted]	$ -	[redacted]
2034	$ 948,636,002	$ 201,796,033	$0	$1,150,432,035	[redacted]	$194,402,098	[redacted]		$0	[redacted]	$ -	[redacted]
2035	$ 948,636,002	$ 205,818,937	$0	$1,154,454,939	[redacted]	$187,590,270	[redacted]		$0	[redacted]	$ -	[redacted]
2036	$ 951,235,004	$ 210,497,420	$0	$1,161,732,424	[redacted]	$180,813,806	[redacted]		$0	[redacted]	$ -	[redacted]
2037	$ 948,636,002	$ 214,107,701	$0	$1,162,743,703	[redacted]	$174,002,391	[redacted]		$0	[redacted]	$ -	[redacted]
2038	$ 948,636,002	$ 218,376,811	$0	$1,167,012,812	[redacted]	$167,308,670	[redacted]		$0	[redacted]	$ -	[redacted]
2039	$ 948,636,002	$ 222,731,293	$0	$1,171,367,294	[redacted]	$160,868,941	[redacted]		$0	[redacted]	$ -	[redacted]
2040	$ 951,235,004	$ 227,795,246	$0	$1,179,030,251	[redacted]	$154,893,976	[redacted]		$0	[redacted]	$ -	[redacted]
2041	$ 948,636,002	$ 231,703,238	$0	$1,180,339,240	[redacted]	$149,455,418	[redacted]		$0	[redacted]	$ -	[redacted]
2042	$ 948,636,002	$ 236,324,219	$0	$1,184,960,221	[redacted]	$144,257,250	[redacted]		$0	[redacted]	$ -	[redacted]
2043	$ 948,636,002	$ 241,037,609	$0	$1,189,673,611	[redacted]	$139,068,151	[redacted]		$0	[redacted]	$ -	[redacted]
2044	$ 951,235,004	$ 246,518,805	$0	$1,197,753,809	[redacted]	$133,888,349	[redacted]		$0	[redacted]	$ -	[redacted]
2045	$ 948,636,002	$ 250,749,045	$0	$1,199,385,047	[redacted]	$128,728,150	[redacted]		$0	[redacted]	$ -	[redacted]
2046	$ 948,636,002	$ 255,750,899	$0	$1,204,386,901	[redacted]	$124,266,112	[redacted]		$0	[redacted]	$ -	[redacted]
2047	$ 948,636,002	$ 260,852,779	$0	$1,209,488,781	[redacted]	$119,814,090	[redacted]		$0	[redacted]	$ -	[redacted]
2048	$ 951,235,004	$ 266,785,608	$0	$1,218,020,612	[redacted]	$115,372,335	[redacted]		$0	[redacted]	$ -	[redacted]
2049	$ 948,636,002	$ 271,364,656	$0	$1,220,000,659	[redacted]	$110,941,107	[redacted]		$0	[redacted]	$ -	[redacted]
2050	$ 948,636,002	$ 276,778,777	$0	$1,225,414,779	[redacted]	$106,520,670	[redacted]		$0	[redacted]	$ -	[redacted]
2051	$ 948,636,002	$ 282,301,168	$0	$1,230,937,169	[redacted]	$101,736,620	[redacted]		$0	[redacted]	$ -	[redacted]
2052	$ 951,235,004	$ 288,722,653	$0	$1,236,957,658	[redacted]	$96,952,924	[redacted]		$0	[redacted]	$ -	[redacted]
2053	$ 948,636,002	$ 293,679,462	$0	$1,242,315,464	[redacted]	$91,510,109	[redacted]		$0	[redacted]	$ -	[redacted]
						Upstream Pipeline Project / Florida Energy Secure line vs. Company B Net Savings						$ 6,672,344,356
						Upstream Pipeline Project / Florida Energy Secure line vs. Company B (@2012) 8.89% NPV Savings						$ 122,719,777

1/ As the Florida EnergySecure Line Project and the Upstream Pipeline project are not projected to be in service prior to January 2014, costs for this option in 2012 and 2013 represent short-term workaround costs required to enable testing and initial usage of the CCEC and RBEC during these years. It is assumed that these initial needs would be served via a combination of (a) re-allocation of firm transportation entitlement rights on FGT (b) acquisition of secondary market capacity and (c) the installation of onsite compression at the CCEC and RBEC as required to increase pressure of delivered gas on FGT to required levels. The RBEC compression costs are embedded in overall Energy Secure Line project estimate and the CCEC on-site compression cost is added as a stand alone incremental revenue requirement (as estimated by FPL). In addition, as a conservative assumption, it is assumed that secondary capacity required during these years is consistent with quantities purchased from Company B under the Company B alternative and is purchased at market values (same value as release capacity is presumed sold). Finally, transportation fuel and usage costs are assumed identical to those with Company B service as the gas would be delivered via Company B during these years with this alternative.

Attachment I

Year	2012	2013	2014	2015	2016	2017	2018
Company B Proposed Rate - Escalated at 2.5% per year 1/ 2/	$ 1.627	$ 1.627	$ 1.646	$ 1.687	$ 1.729	$ 1.772	$ 1.816
Rate for Potential Pipeline from Transco 85 to Company B - Escalated at 2.5% per year 3/	N/A	$ 0.200	$ 0.202	$ 0.207	$ 0.212	$ 0.217	$ 0.223
FPL Demand (MMBtu/day)			400,000	400,000	400,000	400,000	400,000
Company B Base Proposal							
Company B MDQ (MMBtu/day)	50,000	400,000	400,000	400,000	400,000	400,000	400,000
Company B Res. Fee ($/MMBtu)	$ 1.627	$ 1.627	$ 1.627	$ 1.627	$ 1.627	$ 1.627	$ 1.627
MDQ on Transco 85 to Company B ($/MMBtu) (grossed up for Company B Fuel)	-	413,479	413,479	413,479	413,479	413,479	413,479
Transco 85 to Company B Reservation Charge ($/MMBtu)	$ -	$ 0.200	$ 0.200	$ 0.200	$ 0.200	$ 0.200	$ 0.200
Capacity Addition 1							
MDQ (MMBtu/day)			-	-	-	-	-
Reservation Charge ($/MMBtu)			$ -	$ -	$ -	$ -	$ -
MDQ on Transco 85 to Company B ($/MMBtu) (grossed up for Company B Fuel)			-	-	-	-	-
Transco 85 to Company B Reservation Charge ($/MMBtu)			$ -	$ -	$ -	$ -	$ -
Capacity Addition 2							
MDQ (MMBtu/day)			-	-	-	-	-
Reservation Charge ($/MMBtu)			$ -	$ -	$ -	$ -	$ -
MDQ on Transco 85 to Company B ($/MMBtu) (grossed up for Company B Fuel)			-	-	-	-	-
Transco 85 to Company B Reservation Charge ($/MMBtu)			$ -	$ -	$ -	$ -	$ -
Capacity Addition 3							
MDQ (MMBtu/day)			-	-	-	-	-
Reservation Charge ($/MMBtu)			$ -	$ -	$ -	$ -	$ -
MDQ on Transco 85 to Company B ($/MMBtu) (grossed up for Company B Fuel)			-	-	-	-	-
Transco 85 to Company B Reservation Charge ($/MMBtu)			$ -	$ -	$ -	$ -	$ -
Capacity Addition 4							
MDQ (MMBtu/day)			-	-	-	-	-
Reservation Charge ($/MMBtu)			$ -	$ -	$ -	$ -	$ -
MDQ on Transco 85 to Company B ($/MMBtu) (grossed up for Company B Fuel)			-	-	-	-	-
Transco 85 to Company B Reservation Charge ($/MMBtu)			$ -	$ -	$ -	$ -	$ -
Capacity Addition 5							
MDQ (MMBtu/day)			-	-	-	-	-
Reservation Charge ($/MMBtu)			$ -	$ -	$ -	$ -	$ -
MDQ on Transco 85 to Company B ($/MMBtu) (grossed up for Company B Fuel)			-	-	-	-	-
Transco 85 to Company B Reservation Charge ($/MMBtu)			$ -	$ -	$ -	$ -	$ -
Capacity Addition 6							
MDQ (MMBtu/day)			-	-	-	-	-
Reservation Charge ($/MMBtu)			$ -	$ -	$ -	$ -	$ -
MDQ on Transco 85 to Company B ($/MMBtu) (grossed up for Company B Fuel)			-	-	-	-	-
Transco 85 to Company B Reservation Charge ($/MMBtu)			$ -	$ -	$ -	$ -	$ -
Annual Cost of Reservation Charges	**$ 9,924,700**	**$ 109,254,548**	**$ 267,725,998**	**$ 267,725,998**	**$ 268,459,494**	**$ 267,725,998**	**$ 267,725,998**

1/ The initial tranche of capacity under the Company B proposal rate has been set as equal to the quoted rate of $1.68 per MMBtu quoted in Company B's March 18, 2009 proposal less a steel price tracker adjustment of $0.0085/MMBtu per $100 per ton of steel cost change. based upon a quoted steel cost of $1975/ton and a current steel cost of $1,350/ton.

2/ In support of future (beyond proposal capacity) natural gas demand, the Company B proposal rate has been esclated at an annual average of 2.5% per year. As initial proposal included 50,000 MMBtu/day in service Sept 1, 2012 and 350,000 in service Sept 1, 2013, the escalated rate in 2014 includes an escalation of 12.5% of the cost at 2.5% per year for sixteen months and the remaining 87.5% of the cost at 2.5% per year for four months.

3/ Assumes lateral to Transco St 85 placed in service in Sept. 2013.

Attachment I

Year	2019	2020	2021	2022	2023	2024	2025
Company B Proposed Rate - Escalated at 2.5% per year 1/ 2/	$ 1.862	$ 1.908	$ 1.956	$ 2.005	$ 2.055	$ 2.107	$ 2.159
Rate for Potential Pipeline from Transco 85 to Company B - Escalated at 2.5% per year 3/	$ 0.228	$ 0.234	$ 0.240	$ 0.246	$ 0.252	$ 0.258	$ 0.265
FPL Demand (MMBtu/day)	400,000	400,000	487,500	575,000	750,000	837,500	1,012,500
Company B Base Proposal							
Company B MDQ (MMBtu/day)	400,000	400,000	400,000	400,000	400,000	400,000	400,000
Company B Res. Fee ($/MMBtu)	$ 1.627	$ 1.627	$ 1.627	$ 1.627	$ 1.627	$ 1.627	$ 1.627
MDQ on Transco 85 to Company B ($/MMBtu) (grossed up for Company B Fuel)	413,479	413,479	413,479	413,479	413,479	413,479	413,479
Transco 85 to Company B Reservation Charge ($/MMBtu)	$ 0.200	$ 0.200	$ 0.200	$ 0.200	$ 0.200	$ 0.200	$ 0.200
Capacity Addition 1							
MDQ (MMBtu/day)	-	-	87,500	87,500	87,500	87,500	87,500
Reservation Charge ($/MMBtu)	$ -	$ -	$ 1.956	$ 1.956	$ 1.956	$ 1.956	$ 1.956
MDQ on Transco 85 to Company B ($/MMBtu) (grossed up for Company B Fuel)	-	-	90,449	90,449	90,449	90,449	90,449
Transco 85 to Company B Reservation Charge ($/MMBtu)	$ -	$ -	$ 0.240	$ 0.240	$ 0.240	$ 0.240	$ 0.240
Capacity Addition 2							
MDQ (MMBtu/day)	-	-	-	87,500	87,500	87,500	87,500
Reservation Charge ($/MMBtu)	$ -	$ -	$ -	$ 2.005	$ 2.005	$ 2.005	$ 2.005
MDQ on Transco 85 to Company B ($/MMBtu) (grossed up for Company B Fuel)	-	-	-	90,449	90,449	90,449	90,449
Transco 85 to Company B Reservation Charge ($/MMBtu)	$ -	$ -	$ -	$ 0.246	$ 0.246	$ 0.246	$ 0.246
Capacity Addition 3							
MDQ (MMBtu/day)	-	-	-	-	175,000	175,000	175,000
Reservation Charge ($/MMBtu)	$ -	$ -	$ -	$ -	$ 2.055	$ 2.055	$ 2.055
MDQ on Transco 85 to Company B ($/MMBtu) (grossed up for Company B Fuel)	-	-	-	-	180,897	180,897	180,897
Transco 85 to Company B Reservation Charge ($/MMBtu)	$ -	$ -	$ -	$ -	$ 0.252	$ 0.252	$ 0.252
Capacity Addition 4							
MDQ (MMBtu/day)	-	-	-	-	-	87,500	87,500
Reservation Charge ($/MMBtu)	$ -	$ -	$ -	$ -	$ -	$ 2.107	$ 2.107
MDQ on Transco 85 to Company B ($/MMBtu) (grossed up for Company B Fuel)	-	-	-	-	-	90,449	90,449
Transco 85 to Company B Reservation Charge ($/MMBtu)	$ -	$ -	$ -	$ -	$ -	$ 0.258	$ 0.258
Capacity Addition 5							
MDQ (MMBtu/day)	-	-	-	-	-	-	175,000
Reservation Charge ($/MMBtu)	$ -	$ -	$ -	$ -	$ -	$ -	$ 2.159
MDQ on Transco 85 to Company B ($/MMBtu) (grossed up for Company B Fuel)	-	-	-	-	-	-	180,897
Transco 85 to Company B Reservation Charge ($/MMBtu)	$ -	$ -	$ -	$ -	$ -	$ -	$ 0.265
Capacity Addition 6							
MDQ (MMBtu/day)	-	-	-	-	-	-	-
Reservation Charge ($/MMBtu)	$ -	$ -	$ -	$ -	$ -	$ -	$ -
MDQ on Transco 85 to Company B ($/MMBtu) (grossed up for Company B Fuel)	-	-	-	-	-	-	-
Transco 85 to Company B Reservation Charge ($/MMBtu)	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Annual Cost of Reservation Charges	**$ 267,725,998**	**$ 268,459,494**	**$ 338,114,604**	**$ 410,262,924**	**$ 558,166,981**	**$ 635,704,708**	**$ 789,359,510**

1/ The initial tranche of capacity under the Company B proposal rate has been set as equal to the quoted rate of $1.68 per MMBtu quoted in Company B's March 18, 2009 proposal less a steel price tracker adjustment of $0.0085/MMBtu per $100 per ton of steel cost change. based upon a quoted steel cost of $1975/ton and a current steel cost of $1,350/ton.

2/ In support of future (beyond proposal capacity) natural gas demand, the Company B proposal rate has been esclated at an annual average of 2.5% per year. As initial proposal included 50,000 MMBtu/day in service Sept 1, 2012 and 350,000 in service Sept 1, 2013, the escalated rate in 2014 includes an escalation of 12.5% of the cost at 2.5% per year for sixteen months and the remaining 87.5% of the cost at 2.5% per year for four months.

3/ Assumes lateral to Transco St 85 placed in service in Sept. 2013.

Attachment I

Year	2026	2027	2028	2029	2030	2031	2032
Company B Proposed Rate - Escalated at 2.5% per year 1/ 2/	$ 2.213	$ 2.269	$ 2.325	$ 2.383	$ 2.443	$ 2.504	$ 2.567
Rate for Potential Pipeline from Transco 85 to Company B - Escalated at 2.5% per year 3/	$ 0.271	$ 0.278	$ 0.285	$ 0.292	$ 0.299	$ 0.307	$ 0.315
FPL Demand (MMBtu/day)	1,187,500	1,187,500	1,187,500	1,187,500	1,187,500	1,187,500	1,187,500
Company B Base Proposal							
Company B MDQ (MMBtu/day)	400,000	400,000	400,000	400,000	400,000	400,000	400,000
Company B Res. Fee ($/MMBtu)	$ 1.627	$ 1.627	$ 1.627	$ 1.627	$ 1.627	$ 1.627	$ 1.627
MDQ on Transco 85 to Company B ($/MMBtu) (grossed up for Company B Fuel)	413,479	413,479	413,479	413,479	413,479	413,479	413,479
Transco 85 to Company B Reservation Charge ($/MMBtu)	$ 0.200	$ 0.200	$ 0.200	$ 0.200	$ 0.200	$ 0.200	$ 0.200
Capacity Addition 1							
MDQ (MMBtu/day)	87,500	87,500	87,500	87,500	87,500	87,500	87,500
Reservation Charge ($/MMBtu)	$ 1.956	$ 1.956	$ 1.956	$ 1.956	$ 1.956	$ 1.956	$ 1.956
MDQ on Transco 85 to Company B ($/MMBtu) (grossed up for Company B Fuel)	90,449	90,449	90,449	90,449	90,449	90,449	90,449
Transco 85 to Company B Reservation Charge ($/MMBtu)	$ 0.240	$ 0.240	$ 0.240	$ 0.240	$ 0.240	$ 0.240	$ 0.240
Capacity Addition 2							
MDQ (MMBtu/day)	87,500	87,500	87,500	87,500	87,500	87,500	87,500
Reservation Charge ($/MMBtu)	$ 2.005	$ 2.005	$ 2.005	$ 2.005	$ 2.005	$ 2.005	$ 2.005
MDQ on Transco 85 to Company B ($/MMBtu) (grossed up for Company B Fuel)	90,449	90,449	90,449	90,449	90,449	90,449	90,449
Transco 85 to Company B Reservation Charge ($/MMBtu)	$ 0.246	$ 0.246	$ 0.246	$ 0.246	$ 0.246	$ 0.246	$ 0.246
Capacity Addition 3							
MDQ (MMBtu/day)	175,000	175,000	175,000	175,000	175,000	175,000	175,000
Reservation Charge ($/MMBtu)	$ 2.055	$ 2.055	$ 2.055	$ 2.055	$ 2.055	$ 2.055	$ 2.055
MDQ on Transco 85 to Company B ($/MMBtu) (grossed up for Company B Fuel)	180,897	180,897	180,897	180,897	180,897	180,897	180,897
Transco 85 to Company B Reservation Charge ($/MMBtu)	$ 0.252	$ 0.252	$ 0.252	$ 0.252	$ 0.252	$ 0.252	$ 0.252
Capacity Addition 4							
MDQ (MMBtu/day)	87,500	87,500	87,500	87,500	87,500	87,500	87,500
Reservation Charge ($/MMBtu)	$ 2.107	$ 2.107	$ 2.107	$ 2.107	$ 2.107	$ 2.107	$ 2.107
MDQ on Transco 85 to Company B ($/MMBtu) (grossed up for Company B Fuel)	90,449	90,449	90,449	90,449	90,449	90,449	90,449
Transco 85 to Company B Reservation Charge ($/MMBtu)	$ 0.258	$ 0.258	$ 0.258	$ 0.258	$ 0.258	$ 0.258	$ 0.258
Capacity Addition 5							
MDQ (MMBtu/day)	175,000	175,000	175,000	175,000	175,000	175,000	175,000
Reservation Charge ($/MMBtu)	$ 2.159	$ 2.159	$ 2.159	$ 2.159	$ 2.159	$ 2.159	$ 2.159
MDQ on Transco 85 to Company B ($/MMBtu) (grossed up for Company B Fuel)	180,897	180,897	180,897	180,897	180,897	180,897	180,897
Transco 85 to Company B Reservation Charge ($/MMBtu)	$ 0.265	$ 0.265	$ 0.265	$ 0.265	$ 0.265	$ 0.265	$ 0.265
Capacity Addition 6							
MDQ (MMBtu/day)	175,000	175,000	175,000	175,000	175,000	175,000	175,000
Reservation Charge ($/MMBtu)	$ 2.213	$ 2.213	$ 2.213	$ 2.213	$ 2.213	$ 2.213	$ 2.213
MDQ on Transco 85 to Company B ($/MMBtu) (grossed up for Company B Fuel)	180,897	180,897	180,897	180,897	180,897	180,897	180,897
Transco 85 to Company B Reservation Charge ($/MMBtu)	$ 0.271	$ 0.271	$ 0.271	$ 0.271	$ 0.271	$ 0.271	$ 0.271
Annual Cost of Reservation Charges	**$ 948,636,002**	**$ 948,636,002**	**$ 951,235,004**	**$ 948,636,002**	**$ 948,636,002**	**$ 948,636,002**	**$ 951,235,004**

1/ The initial tranche of capacity under the Company B proposal rate has been set as equal to the quoted rate of $1.68 per MMBtu quoted in Company B's March 18, 2009 proposal less a steel price tracker adjustment of $0.0085/MMBtu per $100 per ton of steel cost change. based upon a quoted steel cost of $1975/ton and a current steel cost of $1,350/ton.

2/ In support of future (beyond proposal capacity) natural gas demand, the Company B proposal rate has been esclated at an annual average of 2.5% per year. As initial proposal included 50,000 MMBtu/day in service Sept 1, 2012 and 350,000 in service Sept 1, 2013, the escalated rate in 2014 includes an escalation of 12.5% of the cost at 2.5% per year for sixteen months and the remaining 87.5% of the cost at 2.5% per year for four months.

3/ Assumes lateral to Transco St 85 placed in service in Sept. 2013.

Attachment I

Year	2033	2034	2035	2036	2037	2038	2039
Company B Proposed Rate - Escalated at 2.5% per year 1/ 2/	$ 2.631	$ 2.697	$ 2.764	$ 2.833	$ 2.904	$ 2.977	$ 3.051
Rate for Potential Pipeline from Transco 85 to Company B - Escalated at 2.5% per year 3/	$ 0.322	$ 0.330	$ 0.339	$ 0.347	$ 0.356	$ 0.365	$ 0.374
FPL Demand (MMBtu/day)	1,187,500	1,187,500	1,187,500	1,187,500	1,187,500	1,187,500	1,187,500
Company B Base Proposal							
Company B MDQ (MMBtu/day)	400,000	400,000	400,000	400,000	400,000	400,000	400,000
Company B Res. Fee ($/MMBtu)	$ 1.627	$ 1.627	$ 1.627	$ 1.627	$ 1.627	$ 1.627	$ 1.627
MDQ on Transco 85 to Company B ($/MMBtu) (grossed up for Company B Fuel)	413,479	413,479	413,479	413,479	413,479	413,479	413,479
Transco 85 to Company B Reservation Charge ($/MMBtu)	$ 0.200	$ 0.200	$ 0.200	$ 0.200	$ 0.200	$ 0.200	$ 0.200
Capacity Addition 1							
MDQ (MMBtu/day)	87,500	87,500	87,500	87,500	87,500	87,500	87,500
Reservation Charge ($/MMBtu)	$ 1.956	$ 1.956	$ 1.956	$ 1.956	$ 1.956	$ 1.956	$ 1.956
MDQ on Transco 85 to Company B ($/MMBtu) (grossed up for Company B Fuel)	90,449	90,449	90,449	90,449	90,449	90,449	90,449
Transco 85 to Company B Reservation Charge ($/MMBtu)	$ 0.240	$ 0.240	$ 0.240	$ 0.240	$ 0.240	$ 0.240	$ 0.240
Capacity Addition 2							
MDQ (MMBtu/day)	87,500	87,500	87,500	87,500	87,500	87,500	87,500
Reservation Charge ($/MMBtu)	$ 2.005	$ 2.005	$ 2.005	$ 2.005	$ 2.005	$ 2.005	$ 2.005
MDQ on Transco 85 to Company B ($/MMBtu) (grossed up for Company B Fuel)	90,449	90,449	90,449	90,449	90,449	90,449	90,449
Transco 85 to Company B Reservation Charge ($/MMBtu)	$ 0.246	$ 0.246	$ 0.246	$ 0.246	$ 0.246	$ 0.246	$ 0.246
Capacity Addition 3							
MDQ (MMBtu/day)	175,000	175,000	175,000	175,000	175,000	175,000	175,000
Reservation Charge ($/MMBtu)	$ 2.055	$ 2.055	$ 2.055	$ 2.055	$ 2.055	$ 2.055	$ 2.055
MDQ on Transco 85 to Company B ($/MMBtu) (grossed up for Company B Fuel)	180,897	180,897	180,897	180,897	180,897	180,897	180,897
Transco 85 to Company B Reservation Charge ($/MMBtu)	$ 0.252	$ 0.252	$ 0.252	$ 0.252	$ 0.252	$ 0.252	$ 0.252
Capacity Addition 4							
MDQ (MMBtu/day)	87,500	87,500	87,500	87,500	87,500	87,500	87,500
Reservation Charge ($/MMBtu)	$ 2.107	$ 2.107	$ 2.107	$ 2.107	$ 2.107	$ 2.107	$ 2.107
MDQ on Transco 85 to Company B ($/MMBtu) (grossed up for Company B Fuel)	90,449	90,449	90,449	90,449	90,449	90,449	90,449
Transco 85 to Company B Reservation Charge ($/MMBtu)	$ 0.258	$ 0.258	$ 0.258	$ 0.258	$ 0.258	$ 0.258	$ 0.258
Capacity Addition 5							
MDQ (MMBtu/day)	175,000	175,000	175,000	175,000	175,000	175,000	175,000
Reservation Charge ($/MMBtu)	$ 2.159	$ 2.159	$ 2.159	$ 2.159	$ 2.159	$ 2.159	$ 2.159
MDQ on Transco 85 to Company B ($/MMBtu) (grossed up for Company B Fuel)	180,897	180,897	180,897	180,897	180,897	180,897	180,897
Transco 85 to Company B Reservation Charge ($/MMBtu)	$ 0.265	$ 0.265	$ 0.265	$ 0.265	$ 0.265	$ 0.265	$ 0.265
Capacity Addition 6							
MDQ (MMBtu/day)	175,000	175,000	175,000	175,000	175,000	175,000	175,000
Reservation Charge ($/MMBtu)	$ 2.213	$ 2.213	$ 2.213	$ 2.213	$ 2.213	$ 2.213	$ 2.213
MDQ on Transco 85 to Company B ($/MMBtu) (grossed up for Company B Fuel)	180,897	180,897	180,897	180,897	180,897	180,897	180,897
Transco 85 to Company B Reservation Charge ($/MMBtu)	$ 0.271	$ 0.271	$ 0.271	$ 0.271	$ 0.271	$ 0.271	$ 0.271
Annual Cost of Reservation Charges	**$ 948,636,002**	**$ 948,636,002**	**$ 948,636,002**	**$ 951,235,004**	**$ 948,636,002**	**$ 948,636,002**	**$ 948,636,002**

1/ The initial tranche of capacity under the Company B proposal rate has been set as equal to the quoted rate of $1.68 per MMBtu quoted in Company B's March 18, 2009 proposal less a steel price tracker adjustment of $0.0085/MMBtu per $100 per ton of steel cost change. based upon a quoted steel cost of $1975/ton and a current steel cost of $1,350/ton.

2/ In support of future (beyond proposal capacity) natural gas demand, the Company B proposal rate has been esclated at an annual average of 2.5% per year. As initial proposal included 50,000 MMBtu/day in service Sept 1, 2012 and 350,000 in service Sept 1, 2013, the escalated rate in 2014 includes an escalation of 12.5% of the cost at 2.5% per year for sixteen months and the remaining 87.5% of the cost at 2.5% per year for four months.

3/ Assumes lateral to Transco St 85 placed in service in Sept. 2013.

Attachment I

Year	2040	2041	2042	2043	2044	2045	2046
Company B Proposed Rate - Escalated at 2.5% per year 1/ 2/	$ 3.127	$ 3.205	$ 3.286	$ 3.368	$ 3.452	$ 3.538	$ 3.627
Rate for Potential Pipeline from Transco 85 to Company B - Escalated at 2.5% per year 3/	$ 0.383	$ 0.393	$ 0.403	$ 0.413	$ 0.423	$ 0.434	$ 0.444
FPL Demand (MMBtu/day)	1,187,500	1,187,500	1,187,500	1,187,500	1,187,500	1,187,500	1,187,500
Company B Base Proposal							
Company B MDQ (MMBtu/day)	400,000	400,000	400,000	400,000	400,000	400,000	400,000
Company B Res. Fee ($/MMBtu)	$ 1.627	$ 1.627	$ 1.627	$ 1.627	$ 1.627	$ 1.627	$ 1.627
MDQ on Transco 85 to Company B ($/MMBtu) (grossed up for Company B Fuel)	413,479	413,479	413,479	413,479	413,479	413,479	413,479
Transco 85 to Company B Reservation Charge ($/MMBtu)	$ 0.200	$ 0.200	$ 0.200	$ 0.200	$ 0.200	$ 0.200	$ 0.200
Capacity Addition 1							
MDQ (MMBtu/day)	87,500	87,500	87,500	87,500	87,500	87,500	87,500
Reservation Charge ($/MMBtu)	$ 1.956	$ 1.956	$ 1.956	$ 1.956	$ 1.956	$ 1.956	$ 1.956
MDQ on Transco 85 to Company B ($/MMBtu) (grossed up for Company B Fuel)	90,449	90,449	90,449	90,449	90,449	90,449	90,449
Transco 85 to Company B Reservation Charge ($/MMBtu)	$ 0.240	$ 0.240	$ 0.240	$ 0.240	$ 0.240	$ 0.240	$ 0.240
Capacity Addition 2							
MDQ (MMBtu/day)	87,500	87,500	87,500	87,500	87,500	87,500	87,500
Reservation Charge ($/MMBtu)	$ 2.005	$ 2.005	$ 2.005	$ 2.005	$ 2.005	$ 2.005	$ 2.005
MDQ on Transco 85 to Company B ($/MMBtu) (grossed up for Company B Fuel)	90,449	90,449	90,449	90,449	90,449	90,449	90,449
Transco 85 to Company B Reservation Charge ($/MMBtu)	$ 0.246	$ 0.246	$ 0.246	$ 0.246	$ 0.246	$ 0.246	$ 0.246
Capacity Addition 3							
MDQ (MMBtu/day)	175,000	175,000	175,000	175,000	175,000	175,000	175,000
Reservation Charge ($/MMBtu)	$ 2.055	$ 2.055	$ 2.055	$ 2.055	$ 2.055	$ 2.055	$ 2.055
MDQ on Transco 85 to Company B ($/MMBtu) (grossed up for Company B Fuel)	180,897	180,897	180,897	180,897	180,897	180,897	180,897
Transco 85 to Company B Reservation Charge ($/MMBtu)	$ 0.252	$ 0.252	$ 0.252	$ 0.252	$ 0.252	$ 0.252	$ 0.252
Capacity Addition 4							
MDQ (MMBtu/day)	87,500	87,500	87,500	87,500	87,500	87,500	87,500
Reservation Charge ($/MMBtu)	$ 2.107	$ 2.107	$ 2.107	$ 2.107	$ 2.107	$ 2.107	$ 2.107
MDQ on Transco 85 to Company B ($/MMBtu) (grossed up for Company B Fuel)	90,449	90,449	90,449	90,449	90,449	90,449	90,449
Transco 85 to Company B Reservation Charge ($/MMBtu)	$ 0.258	$ 0.258	$ 0.258	$ 0.258	$ 0.258	$ 0.258	$ 0.258
Capacity Addition 5							
MDQ (MMBtu/day)	175,000	175,000	175,000	175,000	175,000	175,000	175,000
Reservation Charge ($/MMBtu)	$ 2.159	$ 2.159	$ 2.159	$ 2.159	$ 2.159	$ 2.159	$ 2.159
MDQ on Transco 85 to Company B ($/MMBtu) (grossed up for Company B Fuel)	180,897	180,897	180,897	180,897	180,897	180,897	180,897
Transco 85 to Company B Reservation Charge ($/MMBtu)	$ 0.265	$ 0.265	$ 0.265	$ 0.265	$ 0.265	$ 0.265	$ 0.265
Capacity Addition 6							
MDQ (MMBtu/day)	175,000	175,000	175,000	175,000	175,000	175,000	175,000
Reservation Charge ($/MMBtu)	$ 2.213	$ 2.213	$ 2.213	$ 2.213	$ 2.213	$ 2.213	$ 2.213
MDQ on Transco 85 to Company B ($/MMBtu) (grossed up for Company B Fuel)	180,897	180,897	180,897	180,897	180,897	180,897	180,897
Transco 85 to Company B Reservation Charge ($/MMBtu)	$ 0.271	$ 0.271	$ 0.271	$ 0.271	$ 0.271	$ 0.271	$ 0.271
Annual Cost of Reservation Charges	**$ 951,235,004**	**$ 948,636,002**	**$ 948,636,002**	**$ 948,636,002**	**$ 951,235,004**	**$ 948,636,002**	**$ 948,636,002**

1/ The initial tranche of capacity under the Company B proposal rate has been set as equal to the quoted rate of $1.68 per MMBtu quoted in Company B's March 18, 2009 proposal less a steel price tracker adjustment of $0.0085/MMBtu per $100 per ton of steel cost change. based upon a quoted steel cost of $1975/ton and a current steel cost of $1,350/ton.

2/ In support of future (beyond proposal capacity) natural gas demand, the Company B proposal rate has been esclated at an annual average of 2.5% per year. As initial proposal included 50,000 MMBtu/day in service Sept 1, 2012 and 350,000 in service Sept 1, 2013, the escalated rate in 2014 includes an escalation of 12.5% of the cost at 2.5% per year for sixteen months and the remaining 87.5% of the cost at 2.5% per year for four months.

3/ Assumes lateral to Transco St 85 placed in service in Sept. 2013.

Attachment I

Year	2047	2048	2049	2050	2051	2052	2053
Company B Proposed Rate - Escalated at 2.5% per year 1/ 2/	$ 3.717	$ 3.810	$ 3.905	$ 4.003	$ 4.103	$ 4.206	$ 4.311
Rate for Potential Pipeline from Transco 85 to Company B - Escalated at 2.5% per year 3/	$ 0.456	$ 0.467	$ 0.479	$ 0.491	$ 0.503	$ 0.515	$ 0.528
FPL Demand (MMBtu/day)	1,187,500	1,187,500	1,187,500	1,187,500	1,187,500	1,187,500	1,187,500
Company B Base Proposal							
Company B MDQ (MMBtu/day)	400,000	400,000	400,000	400,000	400,000	400,000	400,000
Company B Res. Fee ($/MMBtu)	$ 1.627	$ 1.627	$ 1.627	$ 1.627	$ 1.627	$ 1.627	$ 1.627
MDQ on Transco 85 to Company B ($/MMBtu) (grossed up for Company B Fuel)	413,479	413,479	413,479	413,479	413,479	413,479	413,479
Transco 85 to Company B Reservation Charge ($/MMBtu)	$ 0.200	$ 0.200	$ 0.200	$ 0.200	$ 0.200	$ 0.200	$ 0.200
Capacity Addition 1							
MDQ (MMBtu/day)	87,500	87,500	87,500	87,500	87,500	87,500	87,500
Reservation Charge ($/MMBtu)	$ 1.956	$ 1.956	$ 1.956	$ 1.956	$ 1.956	$ 1.956	$ 1.956
MDQ on Transco 85 to Company B ($/MMBtu) (grossed up for Company B Fuel)	90,449	90,449	90,449	90,449	90,449	90,449	90,449
Transco 85 to Company B Reservation Charge ($/MMBtu)	$ 0.240	$ 0.240	$ 0.240	$ 0.240	$ 0.240	$ 0.240	$ 0.240
Capacity Addition 2							
MDQ (MMBtu/day)	87,500	87,500	87,500	87,500	87,500	87,500	87,500
Reservation Charge ($/MMBtu)	$ 2.005	$ 2.005	$ 2.005	$ 2.005	$ 2.005	$ 2.005	$ 2.005
MDQ on Transco 85 to Company B ($/MMBtu) (grossed up for Company B Fuel)	90,449	90,449	90,449	90,449	90,449	90,449	90,449
Transco 85 to Company B Reservation Charge ($/MMBtu)	$ 0.246	$ 0.246	$ 0.246	$ 0.246	$ 0.246	$ 0.246	$ 0.246
Capacity Addition 3							
MDQ (MMBtu/day)	175,000	175,000	175,000	175,000	175,000	175,000	175,000
Reservation Charge ($/MMBtu)	$ 2.055	$ 2.055	$ 2.055	$ 2.055	$ 2.055	$ 2.055	$ 2.055
MDQ on Transco 85 to Company B ($/MMBtu) (grossed up for Company B Fuel)	180,897	180,897	180,897	180,897	180,897	180,897	180,897
Transco 85 to Company B Reservation Charge ($/MMBtu)	$ 0.252	$ 0.252	$ 0.252	$ 0.252	$ 0.252	$ 0.252	$ 0.252
Capacity Addition 4							
MDQ (MMBtu/day)	87,500	87,500	87,500	87,500	87,500	87,500	87,500
Reservation Charge ($/MMBtu)	$ 2.107	$ 2.107	$ 2.107	$ 2.107	$ 2.107	$ 2.107	$ 2.107
MDQ on Transco 85 to Company B ($/MMBtu) (grossed up for Company B Fuel)	90,449	90,449	90,449	90,449	90,449	90,449	90,449
Transco 85 to Company B Reservation Charge ($/MMBtu)	$ 0.258	$ 0.258	$ 0.258	$ 0.258	$ 0.258	$ 0.258	$ 0.258
Capacity Addition 5							
MDQ (MMBtu/day)	175,000	175,000	175,000	175,000	175,000	175,000	175,000
Reservation Charge ($/MMBtu)	$ 2.159	$ 2.159	$ 2.159	$ 2.159	$ 2.159	$ 2.159	$ 2.159
MDQ on Transco 85 to Company B ($/MMBtu) (grossed up for Company B Fuel)	180,897	180,897	180,897	180,897	180,897	180,897	180,897
Transco 85 to Company B Reservation Charge ($/MMBtu)	$ 0.265	$ 0.265	$ 0.265	$ 0.265	$ 0.265	$ 0.265	$ 0.265
Capacity Addition 6							
MDQ (MMBtu/day)	175,000	175,000	175,000	175,000	175,000	175,000	175,000
Reservation Charge ($/MMBtu)	$ 2.213	$ 2.213	$ 2.213	$ 2.213	$ 2.213	$ 2.213	$ 2.213
MDQ on Transco 85 to Company B ($/MMBtu) (grossed up for Company B Fuel)	180,897	180,897	180,897	180,897	180,897	180,897	180,897
Transco 85 to Company B Reservation Charge ($/MMBtu)	$ 0.271	$ 0.271	$ 0.271	$ 0.271	$ 0.271	$ 0.271	$ 0.271
Annual Cost of Reservation Charges	**$ 948,636,002**	**$ 951,235,004**	**$ 948,636,002**	**$ 948,636,002**	**$ 948,636,002**	**$ 951,235,004**	**$ 948,636,002**

1/ The initial tranche of capacity under the Company B proposal rate has been set as equal to the quoted rate of $1.68 per MMBtu quoted in Company B's March 18, 2009 proposal less a steel price tracker adjustment of $0.0085/MMBtu per $100 per ton of steel cost change, based upon a quoted steel cost of $1975/ton and a current steel cost of $1,350/ton.

2/ In support of future (beyond proposal capacity) natural gas demand, the Company B proposal rate has been esclated at an annual average of 2.5% per year. As initial proposal included 50,000 MMBtu/day in service Sept 1, 2012 and 350,000 in service Sept 1, 2013, the escalated rate in 2014 includes an escalation of 12.5% of the cost at 2.5% per year for sixteen months and the remaining 87.5% of the cost at 2.5% per year for four months.

3/ Assumes lateral to Transco St 85 placed in service in Sept. 2013.

Attachment II

Projected Usage / Commodity Charges Incurred by FPL with Company B Offer

		Fuel Gas Retained on Company B System					Fuel Gas Retained on Lateral from Transco 85 to Company B				Calculated Cost of Fuel Gas			
Year	FPL Natural Gas Demand Served (MMBtu/day)	Proposed Contract MDQ on Company B (MMBtu/day)	Average Load Factor for New Capacity (%) 1/	Annual Throughput on Company B (MMBtu)	Company B Fuel Rate %	Company B Fuel Gas Retained (MMBtu)	Contract MDQ Lateral Extension (MMBtu/day)	Annual Throughput on Lateral (MMBtu)	Projected Lateral Fuel Rate % 2/	Lateral Fuel Gas Retained (MMBtu)	Henry Hub Cost of Gas ($/MMBtu) 3/	Basis to Transco Zone 4 ($/MMBtu) 4/	Unit Cost of Fuel Gas ($/MMBtu)	Annual Cost of Fuel Gas $
Column	1	2	3	4	5	6	7	8	9	10	11	12	13	14
Source	FPL Load Forecast	Col 1	See Footnote	See Footnote	FGT Phase VIII Filing - Exhibit N	[Col 4 / (1- Col 5)] - Col 4	Col 2 / (1 - Col 5)	Col 7 * days in year * Col 3	See Footnote 2/	[Col 8 / (1- Col 9)] - Col 8	See Footnote 3/	See Footnote 4/	Col 11 + Col 12	Col 13 * (Col 6 + Col 10)
2012	50,000	50,000	0%	-	3.26%	-	51,685	-	0.30%	-	$ 8.130	$ 0.0525	$ 8.1823	$0
2013	400,000	400,000	54%	32,916,000	3.26%	1,109,222	413,479	34,025,222	0.30%	102,383	$ 8.293	$ 0.0525	$ 8.3453	$10,111,164
2014	400,000	400,000	59%	85,422,300	3.26%	2,878,610	413,479	88,300,910	0.30%	265,700	$ 8.692	$ 0.0525	$ 8.7449	$27,496,720
2015	400,000	400,000	72%	104,757,800	3.26%	3,530,188	413,479	108,287,988	0.30%	325,841	$ 9.192	$ 0.0525	$ 9.2445	$35,646,988
2016	400,000	400,000	76%	111,114,000	3.26%	3,744,383	413,479	114,858,383	0.30%	345,612	$ 9.692	$ 0.0525	$ 9.7440	$39,853,091
2017	400,000	400,000	78%	114,002,300	3.26%	3,841,715	413,479	117,844,015	0.30%	354,596	$ 10.291	$ 0.0525	$ 10.3435	$43,404,627
2018	400,000	400,000	79%	115,486,300	3.26%	3,891,724	413,479	119,378,024	0.30%	359,212	$ 11.090	$ 0.0525	$ 11.1428	$47,367,421
2019	400,000	400,000	78%	114,415,400	3.26%	3,855,636	413,479	118,271,036	0.30%	355,881	$ 12.089	$ 0.0525	$ 12.1420	$51,136,030
2020	400,000	400,000	76%	111,570,500	3.26%	3,759,767	413,479	115,330,267	0.30%	347,032	$ 12.742	$ 0.0525	$ 12.7942	$52,543,249
2021	487,500	487,500	75%	133,453,125	3.26%	4,497,180	503,928	137,950,305	0.30%	415,096	$ 12.997	$ 0.0525	$ 13.0490	$64,100,375
2022	575,000	575,000	75%	157,406,250	3.26%	5,304,366	594,377	162,710,616	0.30%	489,601	$ 13.256	$ 0.0525	$ 13.3089	$77,111,429
2023	750,000	750,000	75%	205,312,500	3.26%	6,918,738	775,274	212,231,238	0.30%	638,610	$ 13.522	$ 0.0525	$ 13.5740	$102,583,566
2024	837,500	837,500	75%	229,893,750	3.26%	7,747,091	865,723	237,640,841	0.30%	715,068	$ 13.792	$ 0.0525	$ 13.8444	$117,153,656
2025	1,012,500	1,012,500	75%	277,171,875	3.26%	9,340,297	1,046,620	286,512,172	0.30%	862,123	$ 14.068	$ 0.0525	$ 14.1202	$144,060,449
2026	1,187,500	1,187,500	75%	325,078,125	3.26%	10,954,669	1,227,517	336,032,794	0.30%	1,011,132	$ 14.349	$ 0.0525	$ 14.4015	$172,326,039
2027	1,187,500	1,187,500	75%	325,078,125	3.26%	10,954,669	1,227,517	336,032,794	0.30%	1,011,132	$ 14.636	$ 0.0525	$ 14.6885	$175,759,610
2028	1,187,500	1,187,500	75%	325,968,750	3.26%	10,984,682	1,227,517	336,953,432	0.30%	1,013,902	$ 14.929	$ 0.0525	$ 14.9812	$179,752,972
2029	1,187,500	1,187,500	75%	325,078,125	3.26%	10,954,669	1,227,517	336,032,794	0.30%	1,011,132	$ 15.227	$ 0.0525	$ 15.2797	$182,834,115
2030	1,187,500	1,187,500	75%	325,078,125	3.26%	10,954,669	1,227,517	336,032,794	0.30%	1,011,132	$ 15.532	$ 0.0525	$ 15.5842	$186,477,823
2031	1,187,500	1,187,500	75%	325,078,125	3.26%	10,954,669	1,227,517	336,032,794	0.30%	1,011,132	$ 15.842	$ 0.0525	$ 15.8948	$190,194,397
2032	1,187,500	1,187,500	75%	325,968,750	3.26%	10,984,682	1,227,517	336,953,432	0.30%	1,013,902	$ 16.159	$ 0.0525	$ 16.2116	$194,516,761
2033	1,187,500	1,187,500	75%	325,078,125	3.26%	10,954,669	1,227,517	336,032,794	0.30%	1,011,132	$ 16.482	$ 0.0525	$ 16.5348	$197,852,001
2034	1,187,500	1,187,500	75%	325,078,125	3.26%	10,954,669	1,227,517	336,032,794	0.30%	1,011,132	$ 16.812	$ 0.0525	$ 16.8644	$201,796,033
2035	1,187,500	1,187,500	75%	325,078,125	3.26%	10,954,669	1,227,517	336,032,794	0.30%	1,011,132	$ 17.148	$ 0.0525	$ 17.2006	$205,818,937
2036	1,187,500	1,187,500	75%	325,968,750	3.26%	10,984,682	1,227,517	336,953,432	0.30%	1,013,902	$ 17.491	$ 0.0525	$ 17.5435	$210,497,420
2037	1,187,500	1,187,500	75%	325,078,125	3.26%	10,954,669	1,227,517	336,032,794	0.30%	1,011,132	$ 17.841	$ 0.0525	$ 17.8933	$214,107,701
2038	1,187,500	1,187,500	75%	325,078,125	3.26%	10,954,669	1,227,517	336,032,794	0.30%	1,011,132	$ 18.198	$ 0.0525	$ 18.2501	$218,376,811
2039	1,187,500	1,187,500	75%	325,078,125	3.26%	10,954,669	1,227,517	336,032,794	0.30%	1,011,132	$ 18.561	$ 0.0525	$ 18.6140	$222,731,293
2040	1,187,500	1,187,500	75%	325,968,750	3.26%	10,984,682	1,227,517	336,953,432	0.30%	1,013,902	$ 18.933	$ 0.0525	$ 18.9852	$227,795,246
2041	1,187,500	1,187,500	75%	325,078,125	3.26%	10,954,669	1,227,517	336,032,794	0.30%	1,011,132	$ 19.311	$ 0.0525	$ 19.3638	$231,703,238
2042	1,187,500	1,187,500	75%	325,078,125	3.26%	10,954,669	1,227,517	336,032,794	0.30%	1,011,132	$ 19.697	$ 0.0525	$ 19.7500	$236,324,219
2043	1,187,500	1,187,500	75%	325,078,125	3.26%	10,954,669	1,227,517	336,032,794	0.30%	1,011,132	$ 20.091	$ 0.0525	$ 20.1439	$241,037,609
2044	1,187,500	1,187,500	75%	325,968,750	3.26%	10,984,682	1,227,517	336,953,432	0.30%	1,013,902	$ 20.493	$ 0.0525	$ 20.5457	$246,518,805
2045	1,187,500	1,187,500	75%	325,078,125	3.26%	10,954,669	1,227,517	336,032,794	0.30%	1,011,132	$ 20.903	$ 0.0525	$ 20.9555	$250,749,045
2046	1,187,500	1,187,500	75%	325,078,125	3.26%	10,954,669	1,227,517	336,032,794	0.30%	1,011,132	$ 21.321	$ 0.0525	$ 21.3735	$255,750,899
2047	1,187,500	1,187,500	75%	325,078,125	3.26%	10,954,669	1,227,517	336,032,794	0.30%	1,011,132	$ 21.747	$ 0.0525	$ 21.7999	$260,852,779
2048	1,187,500	1,187,500	75%	325,968,750	3.26%	10,984,682	1,227,517	336,953,432	0.30%	1,013,902	$ 22.182	$ 0.0525	$ 22.2348	$266,785,608
2049	1,187,500	1,187,500	75%	325,078,125	3.26%	10,954,669	1,227,517	336,032,794	0.30%	1,011,132	$ 22.626	$ 0.0525	$ 22.6784	$271,364,658
2050	1,187,500	1,187,500	75%	325,078,125	3.26%	10,954,669	1,227,517	336,032,794	0.30%	1,011,132	$ 23.078	$ 0.0525	$ 23.1308	$276,778,777
2051	1,187,500	1,187,500	75%	325,078,125	3.26%	10,954,669	1,227,517	336,032,794	0.30%	1,011,132	$ 23.540	$ 0.0525	$ 23.5923	$282,301,168
2052	1,187,500	1,187,500	75%	325,968,750	3.26%	10,984,682	1,227,517	336,953,432	0.30%	1,013,902	$ 24.011	$ 0.0525	$ 24.0631	$288,722,853
2053	1,187,500	1,187,500	75%	325,078,125	3.26%	10,954,669	1,227,517	336,032,794	0.30%	1,011,132	$ 24.491	$ 0.0525	$ 24.5432	$293,679,462

1/ Annual Throughput for the years 2012 through 2020 as per FPL annual gas consumption projections for RBEC and CCEC facilities with Load Factor percentage then calculated as percentage of available capacity. Annual throughput for the years 2021 and beyond based upon assumed 75% capacity usage load factor.

2/ Calculated fuel rate to transport 600,000 MMBtu/day from Transco 85 at 800 psig to Company B at 900 psig via proposed approximate 72 mile 30" pipeline.

3/ Henry Hub Cost of Gas equal to price included in FPL fuel price forecast developed in November 2008.

4/ Basis differential between Henry Hub and Transco Station 85 equal to value included within FPL fuel price forecast developed in November 2008.

Attachment III A

Total Annual Revenue Requirements for Florida EnergySecure Line Project

	RR to offset Project Investment		Incremental Capacity Required			Value of Incremental Capacity Purchases: Case A - Current Market			Value of Incremental Capacity Purchases: Case B - FGT Phase III Max Rate			Value of Incremental Capacity Purchases: Case C - No Spot Market Capacity Value		
Year	Cost of On-Site Compression at CCEC Facility ($)	Annual Florida EnergySecure Line Revenue Requirements ($)	Peak Day Demand Served by Incremental Capacity (MMBtu/day)	Florida EnergySecure Line Project Capacity (MMBtu/day)	Incremental Capacity to be Purchased in Spot Market (MMBtu/day)	Unit Cost of Spot Market Capacity ($/MMBtu)	Cost of Spot Market Capacity ($)	Total Cost of Energy Secure Line Project ($)	Unit Cost of Spot Market Capacity ($/MMBtu)	Cost of Spot Market Capacity ($)	Total Cost of Energy Secure Line Project ($)	Unit Cost of Spot Market Capacity ($/MMBtu)	Cost of Spot Market Capacity ($)	Total Cost of Energy Secure Line Project ($)
Column	1	2	3	4	5	6	7	8	9	10	11	12	13	14
Source	FPL Revenue Requirements Analysis 1/	FPL Revenue Requirements Analysis 1/	See Footnote 2/	See Footnote 3/	Column 3 - Column 4	See Footnote 4/	Col 5 * Col 6 * days	Col 1 + Col 2 + Col 7	See Footnote 5/	Col 5 * Col 9 * days	Col 1 + Col 2 + Col 10	See Footnote 6/	Col 5 * Col 12 * days	Col 1 + Col 2 + Col 13
Sept 1, 2012 - Dec 1, 2012	$0	$0	-	0	0	$ 0.4614	$0	$0	$ 1.5857	$0	$0	$	$0	$0
Dec 1, 2012 - Jan 1, 2013	$0	$0	30,000	0	30,000	$ 0.4614	$429,102	$429,102	$ 1.5857	$1,474,701	$1,474,701	$	$0	$0
Jan 1, 2013 - March 1, 2013	$700,688	$0	30,000	0	30,000	$ 0.4614	$816,676	$1,517,364	$ 1.5857	$2,806,689	$3,507,375	$	$0	$700,686
March 1, 2013 - Sept 1, 2013	$2,185,192	$0	50,000	0	50,000	$ 0.4614	$4,244,880	$6,430,072	$ 1.5857	$14,588,440	$16,773,632	$	$0	$2,185,192
Sept 1, 2013 - Dec 1, 2013	$1,080,720	$0	200,000	0	200,000	$ 0.4614	$8,397,480	$9,478,200	$ 1.5857	$28,859,740	$29,940,460	$	$0	$1,080,720
Dec 1, 2013 - Jan 1, 2014	$368,157	$0	230,000	0	230,000	$ 0.4614	$3,289,782	$3,657,939	$ 1.5857	$11,306,041	$11,674,198	$	$0	$368,157
Jan 1, 2014 - March 1, 2014	$644,654	$46,369,638	230,000	596,718	0	$ 0.4614	$0	$47,014,291	$ 1.5857	$0	$47,014,291	$	$0	$47,014,291
March 1, 2014 - June 1, 2014	$1,005,224	$72,305,196	250,000	596,718	0	$ 0.4614	$0	$73,310,419	$ 1.5857	$0	$73,310,419	$	$0	$73,310,419
June 1 2014 - Jan 1 2015	$2,338,238	$168,188,172	400,000	596,718	0	$ 0.4614	$0	$170,526,410	$ 1.5857	$0	$170,526,410	$	$0	$170,526,410
2015	$3,820,359	$276,948,894	400,000	596,718	0	$ 0.4729	$0	$280,769,254	$ 1.5857	$0	$280,769,254	$	$0	$280,769,254
2016	$3,663,294	$265,593,549	400,000	596,718	0	$ 0.4848	$0	$269,256,843	$ 1.5857	$0	$269,256,843	$	$0	$269,256,843
2017	$3,515,900	$254,973,624	400,000	596,718	0	$ 0.4969	$0	$258,489,524	$ 1.5857	$0	$258,489,524	$	$0	$258,489,524
2018	$3,377,308	$245,017,656	400,000	596,718	0	$ 0.5093	$0	$248,394,967	$ 1.5857	$0	$248,394,967	$	$0	$248,394,967
2019	$3,244,770	$235,657,891	400,000	596,718	0	$ 0.5220	$0	$238,902,662	$ 1.5857	$0	$238,902,662	$	$0	$238,902,602
2020	$3,114,186	$226,719,020	400,000	596,718	0	$ 0.5351	$0	$229,833,207	$ 1.5857	$0	$229,833,207	$	$0	$229,833,207
2021	$2,983,600	$217,920,487	487,500	596,718	0	$ 0.5485	$0	$220,904,087	$ 1.5857	$0	$220,904,087	$	$0	$220,904,087
2022	$2,853,094	$209,125,724	575,000	596,718	0	$ 0.5622	$0	$211,978,818	$ 1.5857	$0	$211,978,818	$	$0	$211,978,818
2023	$2,722,607	$223,301,255	750,000	800,000	0	$ 0.5762	$0	$226,023,862	$ 1.5857	$0	$226,023,862	$	$0	$226,023,862
2024	$2,592,232	$229,693,220	837,500	1,000,000	0	$ 0.5906	$0	$232,285,452	$ 1.5857	$0	$232,285,452	$	$0	$232,285,452
2025	$2,461,685	$275,039,657	1,012,500	1,250,000	0	$ 0.6054	$0	$277,501,341	$ 1.5857	$0	$277,501,341	$	$0	$277,501,341
2026	$2,331,139	$262,934,831	1,187,500	1,250,000	0	$ 0.6205	$0	$265,265,970	$ 1.5857	$0	$265,265,970	$	$0	$265,265,970
2027	$2,200,713	$250,654,778	1,187,500	1,250,000	0	$ 0.6360	$0	$252,855,491	$ 1.5857	$0	$252,855,491	$	$0	$252,855,491
2028	$2,087,741	$238,595,925	1,187,500	1,250,000	0	$ 0.6519	$0	$240,683,666	$ 1.5857	$0	$240,683,666	$	$0	$240,683,660
2029	$2,010,100	$227,942,533	1,187,500	1,250,000	0	$ 0.6682	$0	$229,952,633	$ 1.5857	$0	$229,952,633	$	$0	$229,952,633
2030	$1,950,040	$219,846,501	1,187,500	1,250,000	0	$ 0.6850	$0	$221,796,541	$ 1.5857	$0	$221,796,541	$	$0	$221,796,541
2031	$1,889,838	$213,033,553	1,187,500	1,250,000	0	$ 0.7021	$0	$214,923,391	$ 1.5857	$0	$214,923,391	$	$0	$214,923,391
2032	$1,829,636	$206,251,970	1,187,500	1,250,000	0	$ 0.7196	$0	$208,081,606	$ 1.5857	$0	$208,081,606	$	$0	$208,081,606
2033	$1,769,101	$199,451,992	1,187,500	1,250,000	0	$ 0.7376	$0	$201,221,093	$ 1.5857	$0	$201,221,093	$	$0	$201,221,063
2034	$1,709,062	$192,693,036	1,187,500	1,250,000	0	$ 0.7561	$0	$194,402,098	$ 1.5857	$0	$194,402,098	$	$0	$194,402,098
2035	$1,649,035	$185,941,236	1,187,500	1,250,000	0	$ 0.7750	$0	$187,590,270	$ 1.5857	$0	$187,590,270	$	$0	$187,590,270
2036	$1,589,401	$179,224,405	1,187,500	1,250,000	0	$ 0.7943	$0	$180,813,806	$ 1.5857	$0	$180,813,806	$	$0	$180,813,806
2037	$1,529,197	$172,473,194	1,187,500	1,250,000	0	$ 0.8142	$0	$174,002,391	$ 1.5857	$0	$174,002,391	$	$0	$174,002,391
2038	$1,469,186	$165,836,485	1,187,500	1,250,000	0	$ 0.8345	$0	$167,305,670	$ 1.5857	$0	$167,305,670	$	$0	$167,305,670
2039	$1,409,191	$159,459,750	1,187,500	1,250,000	0	$ 0.8554	$0	$160,868,941	$ 1.5857	$0	$160,868,941	$	$0	$160,868,941
2040	$1,349,213	$153,544,763	1,187,500	1,250,000	0	$ 0.8768	$0	$154,893,976	$ 1.5857	$0	$154,893,976	$	$0	$154,893,976
2041	$1,289,253	$148,166,165	1,187,500	1,250,000	0	$ 0.8987	$0	$149,455,418	$ 1.5857	$0	$149,455,418	$	$0	$149,455,418
2042	$1,229,311	$143,027,939	1,187,500	1,250,000	0	$ 0.9212	$0	$144,257,250	$ 1.5857	$0	$144,257,250	$	$0	$144,257,250
2043	$1,169,387	$137,898,764	1,187,500	1,250,000	0	$ 0.9442	$0	$139,068,151	$ 1.5857	$0	$139,068,151	$	$0	$139,068,151
2044	$1,109,483	$132,778,867	1,187,500	1,250,000	0	$ 0.9678	$0	$133,888,349	$ 1.5857	$0	$133,888,349	$	$0	$133,888,349
2045	$1,059,669	$127,668,481	1,187,500	1,250,000	0	$ 0.9920	$0	$128,728,150	$ 1.5857	$0	$128,728,150	$	$0	$128,728,150
2046	$1,009,876	$123,256,236	1,187,500	1,250,000	0	$ 1.0168	$0	$124,266,112	$ 1.5857	$0	$124,266,112	$	$0	$124,266,112
2047	$960,103	$118,853,987	1,187,500	1,250,000	0	$ 1.0422	$0	$119,814,090	$ 1.5857	$0	$119,814,090	$	$0	$119,814,090
2048	$910,351	$114,461,985	1,187,500	1,250,000	0	$ 1.0683	$0	$115,372,335	$ 1.5857	$0	$115,372,335	$	$0	$115,372,335
2049	$860,620	$110,080,487	1,187,500	1,250,000	0	$ 1.0950	$0	$110,941,107	$ 1.5857	$0	$110,941,107	$	$0	$110,941,107
2050	$810,911	$105,709,759	1,187,500	1,250,000	0	$ 1.1224	$0	$106,520,670	$ 1.5857	$0	$106,520,670	$	$0	$106,520,670
2051	$761,225	$100,974,595	1,187,500	1,250,000	0	$ 1.1504	$0	$101,735,820	$ 1.5857	$0	$101,735,820	$	$0	$101,735,820
2052	$711,562	$96,241,382	1,187,500	1,250,000	0	$ 1.1792	$0	$96,952,924	$ 1.5857	$0	$96,952,924	$	$0	$96,952,924
2053	$0	$91,510,109	1,187,500	1,250,000	0	$ 1.2087	$0	$91,510,109	$ 1.5857	$0	$91,510,109	$	$0	$91,510,109

1/ Annual Revenue Requirements for 2013 and 2014 allocated pro rata to each listed portion of calendar year. For the years 2015 and beyond, the annual revenue requirements is as provided by FPL.

2/ Peak Day Demand for the years 2012 through 2013 based upon test gas schedule using WCEC 2 test gas schedule as a proxy. WCEC 2 test gas schedule (as provided by FPL) is six months in length and has a peak demand of approximately 30,000 MMBtu/day during the first three months of testing and a peak demand slightly in excess of 50,000 MMBtu/day during the final three months of testing. Thus, the analysis, with a requirement that plants are placed in service as of June 1 of the subject year assumes test gas requirements are equal to 50,000 MMBtu/day for the final three months of testing (March - May 2013 for CCEC and March-May 2014 for RBEC). 30,000 MMBtu/day for the previous three months of testing (December 2012 - February 2013 for CCEC and December 2013 - February 2014 for RBEC) and 0 MMBtu/day peak prior to six months before a plant is placed in service. After the in-service date, capacity requirements are set as equal to the lower of the peak demand in FPL's Load Forecast or projected capacity purchased under Company B capacity purchase scenario.

3/ Florida EnergySecure Line Capacity for initial years of project based upon the capacity of the Upstream Pipeline Project to deliver to EnergySecure Line (600,000 MMBtu/day) less fuel retention required on EnergySecure Line at 0.55%. After expansions, commencing in 2023, capacity is based upon proposed EnergySecure Line capacity after each expansion project is placed in service.

4/ Unit cost of spot market capacity based upon average price paid by FPL for secondary or interruptible transportation capacity into Florida ($0.4614/MMBtu) during 2008. As conservative assumption, this value is assumed constant through 2014 and escalated at a rat of 2.5% per year thereafter.

5/ Unit cost of spot market capacity based upon FGT Phase VIII Projected Maximum Tariff Recourse Rate as per Exhibit N of FGT's FERC Certificate Filing.

6/ Assumes significant excess capacity available in marketplace with incremental capacity having no real value. In this instance, it is likely that FPL would have excess capacity in its portfolio leaving no need to purchase incremental capacity.

Attachment III B

Year	2013	2014	2015	2016	2017	2018	2019
Company E Proposed Rate - Escalated		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
FPL Demand (MMBtu/day)		400,000	400,000	400,000	400,000	400,000	400,000
Projected EnergySecure Line Fuel Retention (%)		0.55%	0.55%	0.55%	0.55%	0.55%	0.55%
MDQ Required on Upstream P/L Project (MMBtu/day)		402,212	402,212	402,212	402,212	402,212	402,212
Company E Pipeline Proposal							
MDQ (MMBtu/day)		600,000	600,000	600,000	600,000	600,000	600,000
Upstream Pipeline Project Res. Fee ($/MMBtu)		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Capacity Addition 1							
MDQ (MMBtu/day)		-	-	-	-	-	-
Reservation Charge ($/MMBtu)		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Capacity Addition 2							
MDQ (MMBtu/day)		-	-	-	-	-	-
Reservation Charge ($/MMBtu)		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Capacity Addition 3							
MDQ (MMBtu/day)		-	-	-	-	-	-
Reservation Charge ($/MMBtu)		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Capacity Addition 4							
MDQ (MMBtu/day)		-	-	-	-	-	-
Reservation Charge ($/MMBtu)		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Annual Cost of Reservation Charges		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

1/ The initial tranche of capacity under the Company E proposal rate has been set as equal to the quoted rate of $1.09 per MMBtu as quoted in Company E's proposal less a steel price tracker adjustment of $0.0140/MMBtu per $100 per ton of steel cost change and based upon a quoted steel cost of $2,300/ton and a current steel cost of $1,300/ton.

2/ In support of future (beyond proposal capacity) natural gas demand, the Company E proposal rate has been esclated at an annual average of 2.5% per year.

Attachment III B

Year	2020	2021	2022	2023	2024	2025
Company E Proposed Rate - Escalated	[redacted]					
FPL Demand (MMBtu/day)	400,000	487,500	575,000	750,000	837,500	1,012,500
Projected EnergySecure Line Fuel Retention (%)	0.55%	0.55%	0.93%	0.93%	1.07%	1.69%
MDQ Required on Upstream P/L Project (MMBtu/day)	402,212	490,196	580,398	757,040	846,558	1,029,905
<u>Company E Pipeline Proposal</u>						
MDQ (MMBtu/day)	600,000	600,000	600,000	600,000	600,000	600,000
Upstream Pipeline Project Res. Fee ($/MMBtu)	[redacted]					
<u>Capacity Addition 1</u>						
MDQ (MMBtu/day)	-	-		157,040	157,040	157,040
Reservation Charge ($/MMBtu)	[redacted]					
<u>Capacity Addition 2</u>						
MDQ (MMBtu/day)	-	-	-		89,518	89,518
Reservation Charge ($/MMBtu)	[redacted]					
<u>Capacity Addition 3</u>						
MDQ (MMBtu/day)	[redacted]					
Reservation Charge ($/MMBtu)						
<u>Capacity Addition 4</u>						
MDQ (MMBtu/day)	-	-	-	-	-	
Reservation Charge ($/MMBtu)	$ -	$ -	$ -	$ -	$ -	
Annual Cost of Reservation Charges	[redacted]					

1/ The initial tranche of capacity under the Company E proposal rate has been set as equal to the quoted rate of $1.09 per MMBtu as quoted in Company E's proposal less a steel price tracker adjustment of $0.0140/MMBtu per $100 per ton of steel cost change and based upon a quoted steel cost of $2,300/ton and a current steel cost of $1,300/ton.

2/ In support of future (beyond proposal capacity) natural gas demand, the Company E proposal rate has been esclated at an annual average of 2.5% per year.

Attachment III B

Year	2026	2027	2028	2029	2030	2031
Company E Proposed Rate - Escalated	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
FPL Demand (MMBtu/day)	1,187,500	1,187,500	1,187,500	1,187,500	1,187,500	1,187,500
Projected EnergySecure Line Fuel Retention (%)	1.69%	1.69%	1.69%	1.69%	1.69%	1.69%
MDQ Required on Upstream P/L Project (MMBtu/day)	1,207,914	1,207,914	1,207,914	1,207,914	1,207,914	1,207,914
Company E Pipeline Proposal						
MDQ (MMBtu/day)	600,000	600,000	600,000	600,000	600,000	600,000
Upstream Pipeline Project Res. Fee ($/MMBtu)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Capacity Addition 1						
MDQ (MMBtu/day)	157,040	157,040	157,040	157,040	157,040	157,040
Reservation Charge ($/MMBtu)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Capacity Addition 2						
MDQ (MMBtu/day)	89,518	89,518	89,518	89,518	89,518	89,518
Reservation Charge ($/MMBtu)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Capacity Addition 3						
MDQ (MMBtu/day)	183,347	183,347	183,347	183,347	183,347	183,347
Reservation Charge ($/MMBtu)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Capacity Addition 4						
MDQ (MMBtu/day)	178,008	178,008	178,008	178,008	178,008	178,008
Reservation Charge ($/MMBtu)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Annual Cost of Reservation Charges	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

1/ The initial tranche of capacity under the Company E proposal rate has been set as equal to the quoted rate of $1.09 per MMBtu as quoted in Company E's proposal less a steel price tracker adjustment of $0.0140/MMBtu per $100 per ton of steel cost change and based upon a quoted steel cost of $2,300/ton and a current steel cost of $1,300/ton.

2/ In support of future (beyond proposal capacity) natural gas demand, the Company E proposal rate has been esclated at an annual average of 2.5% per year.

Attachment III B

Year	2032	2033	2034	2035	2036	2037
Company E Proposed Rate - Escalated	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
FPL Demand (MMBtu/day)	1,187,500	1,187,500	1,187,500	1,187,500	1,187,500	1,187,500
Projected EnergySecure Line Fuel Retention (%)	1.69%	1.69%	1.69%	1.69%	1.69%	1.69%
MDQ Required on Upstream P/L Project (MMBtu/day)	1,207,914	1,207,914	1,207,914	1,207,914	1,207,914	1,207,914
Company E Pipeline Proposal						
MDQ (MMBtu/day)	600,000	600,000	600,000	600,000	600,000	600,000
Upstream Pipeline Project Res. Fee ($/MMBtu)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Capacity Addition 1						
MDQ (MMBtu/day)	157,040	157,040	157,040	157,040	157,040	157,040
Reservation Charge ($/MMBtu)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Capacity Addition 2						
MDQ (MMBtu/day)	89,518	89,518	89,518	89,518	89,518	89,518
Reservation Charge ($/MMBtu)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Capacity Addition 3						
MDQ (MMBtu/day)	183,347	183,347	183,347	183,347	183,347	183,347
Reservation Charge ($/MMBtu)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Capacity Addition 4						
MDQ (MMBtu/day)	178,008	178,008	178,008	178,008	178,008	178,008
Reservation Charge ($/MMBtu)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Annual Cost of Reservation Charges	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

1/ The initial tranche of capacity under the Company E proposal rate has been set as equal to the quoted rate of $1.09 per MMBtu as quoted in Company E's proposal less a steel price tracker adjustment of $0.0140/MMBtu per $100 per ton of steel cost change and based upon a quoted steel cost of $2,300/ton and a current steel cost of $1,300/ton.

2/ In support of future (beyond proposal capacity) natural gas demand, the Company E proposal rate has been esclated at an annual average of 2.5% per year.

Attachment III B

Year	2038	2039	2040	2041	2042	2043
Company E Proposed Rate - Escalated	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
FPL Demand (MMBtu/day)	1,187,500	1,187,500	1,187,500	1,187,500	1,187,500	1,187,500
Projected EnergySecure Line Fuel Retention (%)	1.69%	1.69%	1.69%	1.69%	1.69%	1.69%
MDQ Required on Upstream P/L Project (MMBtu/day)	1,207,914	1,207,914	1,207,914	1,207,914	1,207,914	1,207,914
Company E Pipeline Proposal						
MDQ (MMBtu/day)	600,000	600,000	600,000	600,000	600,000	600,000
Upstream Pipeline Project Res. Fee ($/MMBtu)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Capacity Addition 1						
MDQ (MMBtu/day)	157,040	157,040	157,040	157,040	157,040	157,040
Reservation Charge ($/MMBtu)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Capacity Addition 2						
MDQ (MMBtu/day)	89,518	89,518	89,518	89,518	89,518	89,518
Reservation Charge ($/MMBtu)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Capacity Addition 3						
MDQ (MMBtu/day)	183,347	183,347	183,347	183,347	183,347	183,347
Reservation Charge ($/MMBtu)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Capacity Addition 4						
MDQ (MMBtu/day)	178,008	178,008	178,008	178,008	178,008	178,008
Reservation Charge ($/MMBtu)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Annual Cost of Reservation Charges	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

1/ The initial tranche of capacity under the Company E proposal rate has been set as equal to the quoted rate of $1.09 per MMBtu as quoted in Company E's proposal less a steel price tracker adjustment of $0.0140/MMBtu per $100 per ton of steel cost change and based upon a quoted steel cost of $2,300/ton and a current steel cost of $1,300/ton.

2/ In support of future (beyond proposal capacity) natural gas demand, the Company E proposal rate has been esclated at an annual average of 2.5% per year.

Attachment III B

Year	2044	2045	2046	2047	2048	2049
Company E Proposed Rate - Escalated	[redacted]					
FPL Demand (MMBtu/day)	1,187,500	1,187,500	1,187,500	1,187,500	1,187,500	1,187,500
Projected EnergySecure Line Fuel Retention (%)	1.69%	1.69%	1.69%	1.69%	1.69%	1.69%
MDQ Required on Upstream P/L Project (MMBtu/day)	1,207,914	1,207,914	1,207,914	1,207,914	1,207,914	1,207,914
Company E Pipeline Proposal						
MDQ (MMBtu/day)	600,000	600,000	600,000	600,000	600,000	600,000
Upstream Pipeline Project Res. Fee ($/MMBtu)	[redacted]					
Capacity Addition 1						
MDQ (MMBtu/day)	157,040	157,040	157,040	157,040	157,040	157,040
Reservation Charge ($/MMBtu)	[redacted]					
Capacity Addition 2						
MDQ (MMBtu/day)	89,518	89,518	89,518	89,518	89,518	89,518
Reservation Charge ($/MMBtu)	[redacted]					
Capacity Addition 3						
MDQ (MMBtu/day)	183,347	183,347	183,347	183,347	183,347	183,347
Reservation Charge ($/MMBtu)	[redacted]					
Capacity Addition 4						
MDQ (MMBtu/day)	178,008	178,008	178,008	178,008	178,008	178,008
Reservation Charge ($/MMBtu)	[redacted]					
Annual Cost of Reservation Charges	[redacted]					

1/ The initial tranche of capacity under the Company E proposal rate has been set as equal to the quoted rate of $1.09 per MMBtu as quoted in Company E's proposal less a steel price tracker adjustment of $0.0140/MMBtu per $100 per ton of steel cost change and based upon a quoted steel cost of $2,300/ton and a current steel cost of $1,300/ton.

2/ In support of future (beyond proposal capacity) natural gas demand, the Company E proposal rate has been esclated at an annual average of 2.5% per year.

Attachment III B

Year	2050	2051	2052	2053
Company E Proposed Rate - Escalated	[redacted]	[redacted]	[redacted]	[redacted]
FPL Demand (MMBtu/day)	1,187,500	1,187,500	1,187,500	1,187,500
Projected EnergySecure Line Fuel Retention (%)	1.69%	1.69%	1.69%	1.69%
MDQ Required on Upstream P/L Project (MMBtu/day)	1,207,914	1,207,914	1,207,914	1,207,914
Company E Pipeline Proposal				
MDQ (MMBtu/day)	600,000	600,000	600,000	600,000
Upstream Pipeline Project Res. Fee ($/MMBtu)	[redacted]	[redacted]	[redacted]	[redacted]
Capacity Addition 1				
MDQ (MMBtu/day)	157,040	157,040	157,040	157,040
Reservation Charge ($/MMBtu)	[redacted]	[redacted]	[redacted]	[redacted]
Capacity Addition 2				
MDQ (MMBtu/day)	89,518	89,518	89,518	89,518
Reservation Charge ($/MMBtu)	[redacted]	[redacted]	[redacted]	[redacted]
Capacity Addition 3				
MDQ (MMBtu/day)	183,347	183,347	183,347	183,347
Reservation Charge ($/MMBtu)	[redacted]	[redacted]	[redacted]	[redacted]
Capacity Addition 4				
MDQ (MMBtu/day)	178,008	178,008	178,008	178,008
Reservation Charge ($/MMBtu)	[redacted]	[redacted]	[redacted]	[redacted]
Annual Cost of Reservation Charges	[redacted]	[redacted]	[redacted]	[redacted]

1/ The initial tranche of capacity under the Company E proposal rate has been set as equal to the quoted rate of $1.09 per MMBtu as quoted in Company E's proposal less a steel price tracker adjustment of $0.0140/MMBtu per $100 per ton of steel cost change and based upon a quoted steel cost of $2,300/ton and a current steel cost of $1,300/ton.

2/ In support of future (beyond proposal capacity) natural gas demand, the Company E proposal rate has been esclated at an annual average of 2.5% per year.

Attachment IV

Projected Usage / Commodity Charges Incurred by FPL with Upstream Pipeline / FPL Intrastate Pipeline Project

			Fuel Gas Burned on EnergySecure Line			Fuel Gas Retained by Upstream Pipeline Project				Calculated Cost of Fuel Gas				Usage Charges on Upstream Pipeline Project				
Year	FPL Natural Gas Demand Served (MMBtu/day)	Average Load Factor for for new capacity (%) 1/	Gas Transported on Florida EnergySecure Line (MMBtu/year)	Florida EnergySecure Line Fuel Rate %	Fuel Gas Consumed on Florida EnergySecure Line (MMBtu/year)	Projected Contract MDQ on Upstream Pipeline Project (MMBtu/day)	Annual Throughput Upstream Pipeline Project (MMBtu/year)	Upstream Pipeline Project Fuel Retention %	Total Projected Fuel Gas Retained (MMBtu/yr)	Henry Hub Cost of Gas ($/MMBtu) 2/	Basis to Transco Zone 4 ($/MMBtu) 3/	Unit Cost of Fuel Gas ($/MMBtu)	Annual Cost of Fuel Gas ($/Year)	Annual Throughput Upstream Pipeline (MMBtu/year)	Upstream Pipeline Proposed Comm. Rate ($/MMBtu)	Annual Cost of Usage Charges ($/Year)	Total Upstream Pipeline & EnergySecure Line Usage Costs ($/Year)	Unit Cost of Usage Charges per MMBtu Transported on Upstream P/L / EnergySecure ($/MMBtu)
Column	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18
Source	FPL Load Forecast	Footnote 1/	Footnote 1/	FPL - Collins Estimates	Col 3 * Col 4	Col 1 * (1 + Col 4)	Col 6 * Col 2 * days in year	Company E Bid	[Col 7 / (1 - Col 8)] - Col 7	Footnote 2/	Footnote 3/	Col 10 + Col 11	Col 12 * (Col 5 + Col 9)	Col 7	Footnote 4/	Col 1 * days in year * Col 2 * Col 15	Col 13 + Col 16	Col 17 / Col 3
2014	400,000	59%	85,422,300	0.55%	469,822	402,200	85,892,122	[redacted]	[redacted]	$ 8.692	$ 0.0525	$ 8.7449	[redacted]	85,892,123	[redacted]	[redacted]	[redacted]	[redacted]
2015	400,000	72%	104,757,800	0.55%	576,168	402,200	105,333,968	[redacted]	[redacted]	$ 9.192	$ 0.0525	$ 9.2445	[redacted]	105,333,968	[redacted]	[redacted]	[redacted]	[redacted]
2016	400,000	76%	111,114,000	0.55%	611,127	402,200	111,725,127	[redacted]	[redacted]	$ 9.692	$ 0.0525	$ 9.7440	[redacted]	111,725,127	[redacted]	[redacted]	[redacted]	[redacted]
2017	400,000	78%	114,002,300	0.55%	627,013	402,200	114,629,313	[redacted]	[redacted]	$ 10.291	$ 0.0525	$ 10.3435	[redacted]	114,629,313	[redacted]	[redacted]	[redacted]	[redacted]
2018	400,000	79%	115,486,300	0.55%	635,175	402,200	116,121,475	[redacted]	[redacted]	$ 11.090	$ 0.0525	$ 11.1425	[redacted]	116,121,475	[redacted]	[redacted]	[redacted]	[redacted]
2019	400,000	78%	114,415,400	0.55%	629,285	402,200	115,044,685	[redacted]	[redacted]	$ 12.089	$ 0.0525	$ 12.1420	[redacted]	115,044,685	[redacted]	[redacted]	[redacted]	[redacted]
2020	400,000	76%	111,570,500	0.55%	613,638	402,200	112,184,138	[redacted]	[redacted]	$ 12.742	$ 0.0525	$ 12.7942	[redacted]	112,184,138	[redacted]	[redacted]	[redacted]	[redacted]
2021	487,500	75%	133,453,125	0.55%	733,992	490,181	134,187,117	[redacted]	[redacted]	$ 12.997	$ 0.0525	$ 13.0490	[redacted]	134,187,117	[redacted]	[redacted]	[redacted]	[redacted]
2022	575,000	75%	157,406,250	0.55%	865,734	578,163	158,271,984	[redacted]	[redacted]	$ 13.256	$ 0.0525	$ 13.3089	[redacted]	158,271,984	[redacted]	[redacted]	[redacted]	[redacted]
2023	750,000	75%	205,312,500	0.93%	1,917,619	757,005	207,230,119	[redacted]	[redacted]	$ 13.522	$ 0.0525	$ 13.5740	[redacted]	207,230,119	[redacted]	[redacted]	[redacted]	[redacted]
2024	837,500	75%	229,893,750	1.07%	2,459,863	846,461	232,353,613	[redacted]	[redacted]	$ 13.792	$ 0.0525	$ 13.8444	[redacted]	232,353,613	[redacted]	[redacted]	[redacted]	[redacted]
2025	1,012,500	75%	277,171,875	1.69%	4,684,206	1,029,611	281,856,081	[redacted]	[redacted]	$ 14.068	$ 0.0525	$ 14.1202	[redacted]	281,856,080	[redacted]	[redacted]	[redacted]	[redacted]
2026	1,187,500	75%	325,078,125	1.69%	5,493,820	1,207,569	330,571,945	[redacted]	[redacted]	$ 14.349	$ 0.0525	$ 14.4015	[redacted]	330,571,945	[redacted]	[redacted]	[redacted]	[redacted]
2027	1,187,500	75%	325,078,125	1.69%	5,493,820	1,207,569	330,571,945	[redacted]	[redacted]	$ 14.636	$ 0.0525	$ 14.6885	[redacted]	330,571,945	[redacted]	[redacted]	[redacted]	[redacted]
2028	1,187,500	75%	325,968,750	1.69%	5,508,872	1,207,569	331,477,622	[redacted]	[redacted]	$ 14.929	$ 0.0525	$ 14.9812	[redacted]	331,477,622	[redacted]	[redacted]	[redacted]	[redacted]
2029	1,187,500	75%	325,078,125	1.69%	5,493,820	1,207,569	330,571,945	[redacted]	[redacted]	$ 15.227	$ 0.0525	$ 15.2797	[redacted]	330,571,945	[redacted]	[redacted]	[redacted]	[redacted]
2030	1,187,500	75%	325,078,125	1.69%	5,493,820	1,207,569	330,571,945	[redacted]	[redacted]	$ 15.532	$ 0.0525	$ 15.5842	[redacted]	330,571,945	[redacted]	[redacted]	[redacted]	[redacted]
2031	1,187,500	75%	325,078,125	1.69%	5,493,820	1,207,569	330,571,945	[redacted]	[redacted]	$ 15.842	$ 0.0525	$ 15.8948	[redacted]	330,571,945	[redacted]	[redacted]	[redacted]	[redacted]
2032	1,187,500	75%	325,968,750	1.69%	5,508,872	1,207,569	331,477,622	[redacted]	[redacted]	$ 16.159	$ 0.0525	$ 16.2118	[redacted]	331,477,622	[redacted]	[redacted]	[redacted]	[redacted]
2033	1,187,500	75%	325,078,125	1.69%	5,493,820	1,207,569	330,571,945	[redacted]	[redacted]	$ 16.482	$ 0.0525	$ 16.5348	[redacted]	330,571,945	[redacted]	[redacted]	[redacted]	[redacted]
2034	1,187,500	75%	325,078,125	1.69%	5,493,820	1,207,569	330,571,945	[redacted]	[redacted]	$ 16.812	$ 0.0525	$ 16.8644	[redacted]	330,571,945	[redacted]	[redacted]	[redacted]	[redacted]
2035	1,187,500	75%	325,078,125	1.69%	5,493,820	1,207,569	330,571,945	[redacted]	[redacted]	$ 17.148	$ 0.0525	$ 17.2006	[redacted]	330,571,945	[redacted]	[redacted]	[redacted]	[redacted]
2036	1,187,500	75%	325,968,750	1.69%	5,508,872	1,207,569	331,477,622	[redacted]	[redacted]	$ 17.491	$ 0.0525	$ 17.5435	[redacted]	331,477,622	[redacted]	[redacted]	[redacted]	[redacted]
2037	1,187,500	75%	325,078,125	1.69%	5,493,820	1,207,569	330,571,945	[redacted]	[redacted]	$ 17.841	$ 0.0525	$ 17.8933	[redacted]	330,571,945	[redacted]	[redacted]	[redacted]	[redacted]
2038	1,187,500	75%	325,078,125	1.69%	5,493,820	1,207,569	330,571,945	[redacted]	[redacted]	$ 18.198	$ 0.0525	$ 18.2501	[redacted]	330,571,945	[redacted]	[redacted]	[redacted]	[redacted]
2039	1,187,500	75%	325,078,125	1.69%	5,493,820	1,207,569	330,571,945	[redacted]	[redacted]	$ 18.561	$ 0.0525	$ 18.6140	[redacted]	330,571,945	[redacted]	[redacted]	[redacted]	[redacted]
2040	1,187,500	75%	325,968,750	1.69%	5,508,872	1,207,569	331,477,622	[redacted]	[redacted]	$ 18.933	$ 0.0525	$ 18.9852	[redacted]	331,477,622	[redacted]	[redacted]	[redacted]	[redacted]
2041	1,187,500	75%	325,078,125	1.69%	5,493,820	1,207,569	330,571,945	[redacted]	[redacted]	$ 19.311	$ 0.0525	$ 19.3636	[redacted]	330,571,945	[redacted]	[redacted]	[redacted]	[redacted]
2042	1,187,500	75%	325,078,125	1.69%	5,493,820	1,207,569	330,571,945	[redacted]	[redacted]	$ 19.697	$ 0.0525	$ 19.7495	[redacted]	330,571,945	[redacted]	[redacted]	[redacted]	[redacted]
2043	1,187,500	75%	325,078,125	1.69%	5,493,820	1,207,569	330,571,945	[redacted]	[redacted]	$ 20.091	$ 0.0525	$ 20.1439	[redacted]	330,571,945	[redacted]	[redacted]	[redacted]	[redacted]
2044	1,187,500	75%	325,968,750	1.69%	5,508,872	1,207,569	331,477,622	[redacted]	[redacted]	$ 20.493	$ 0.0525	$ 20.5457	[redacted]	331,477,622	[redacted]	[redacted]	[redacted]	[redacted]
2045	1,187,500	75%	325,078,125	1.69%	5,493,820	1,207,569	330,571,945	[redacted]	[redacted]	$ 20.903	$ 0.0525	$ 20.9555	[redacted]	330,571,945	[redacted]	[redacted]	[redacted]	[redacted]
2046	1,187,500	75%	325,078,125	1.69%	5,493,820	1,207,569	330,571,945	[redacted]	[redacted]	$ 21.321	$ 0.0525	$ 21.3735	[redacted]	330,571,945	[redacted]	[redacted]	[redacted]	[redacted]
2047	1,187,500	75%	325,078,125	1.69%	5,493,820	1,207,569	330,571,945	[redacted]	[redacted]	$ 21.747	$ 0.0525	$ 21.7998	[redacted]	330,571,945	[redacted]	[redacted]	[redacted]	[redacted]
2048	1,187,500	75%	325,968,750	1.69%	5,508,872	1,207,569	331,477,622	[redacted]	[redacted]	$ 22.182	$ 0.0525	$ 22.2346	[redacted]	331,477,622	[redacted]	[redacted]	[redacted]	[redacted]
2049	1,187,500	75%	325,078,125	1.69%	5,493,820	1,207,569	330,571,945	[redacted]	[redacted]	$ 22.626	$ 0.0525	$ 22.6784	[redacted]	330,571,945	[redacted]	[redacted]	[redacted]	[redacted]
2050	1,187,500	75%	325,078,125	1.69%	5,493,820	1,207,569	330,571,945	[redacted]	[redacted]	$ 23.078	$ 0.0525	$ 23.1306	[redacted]	330,571,945	[redacted]	[redacted]	[redacted]	[redacted]
2051	1,187,500	75%	325,078,125	1.69%	5,493,820	1,207,569	330,571,945	[redacted]	[redacted]	$ 23.540	$ 0.0525	$ 23.5923	[redacted]	330,571,945	[redacted]	[redacted]	[redacted]	[redacted]
2052	1,187,500	75%	325,968,750	1.69%	5,508,872	1,207,569	331,477,622	[redacted]	[redacted]	$ 24.011	$ 0.0525	$ 24.0631	[redacted]	331,477,622	[redacted]	[redacted]	[redacted]	[redacted]
2053	1,187,500	75%	325,078,125	1.69%	5,493,820	1,207,569	330,571,945	[redacted]	[redacted]	$ 24.491	$ 0.0525	$ 24.5432	[redacted]	330,571,945	[redacted]	[redacted]	[redacted]	[redacted]

1/ Capacity usage for the years 2014 through 2020 as per FPL annual gas consumption projections for RBEC and CCEC facilities. Capacity usage for the years 2021 and beyond based upon assumed 75% capacity usage load factor.

2/ Henry Hub Cost of Gas equal to price included in FPL fuel price forecast published November 2008.

3/ Basis differential between Henry Hub and Transco Station 85 equal to value included within FPL fuel price forecast published November 2008.

4/ Commodity cost for 2014 based upon Company E's Upstream Pipeline Project proposal and is escalated at 2.5% per year thereafter.

Attachment V A

Projected Cost Recovery Associated with EnergySecure Line / Upstream Pipeline Project Sales of Excess Capacity

	Cost Recovery for Release/Sale of Excess Capacity Utilizing Various Release Value Assumptions								
				Case A - Current Market		Case B - FGT Max Rate		Case C - No Value	
Year	FPL Natural Gas Fuel Requirements (MMBtu/day)	Pipeline Project Delivery Capacity (MMBtu/day)	Capacity Available For Release (MMBtu/day)	Unit Release Values 1/ ($/MMBtu)	Revenues from Capacity Release ($)	Unit Release Values 2/ ($/MMBtu)	Revenues from Capacity Release ($)	Unit Release Values ($/MMBtu)	Revenues from Capacity Release ($)
Column	1	2	3	4	5	6	7	8	9
Source	Attachment III A, Column 3	Attachment IIIA, Column 4	Col 2 - Col 1	See Footnote 1/	Col 4 * Col 3 * days	See Footnote 2/	Col 6 * Col 3 * days in year	Assume No Value	Col 8 * Col 3 * days in year
Sept 1, 2012 - Dec 1, 2012	-	-	-	$ 0.4614	$0	$ 1.5857	$0	$	$0
Dec 1, 2012 - Jan 1, 2013	30,000			$ 0.4614	$0	$ 1.5857	$0	$	$0
Jan 1, 2013 - March 1, 2013	30,000	-	-	$ 0.4614	$0	$ 1.5857	$0	$	$0
March 1, 2013 - Sept 1, 2013	50,000			$ 0.4614	$0	$ 1.5857	$0	$	$0
Sept 1, 2013 - Dec 1, 2013	200,000	-	-	$ 0.4614	$0	$ 1.5857	$0	$	$0
Dec 1, 2013 - Jan 1, 2014	230,000	-	-	$ 0.4614	$0	$ 1.5857	$0	$	$0
Jan 1, 2014 - March 1, 2014	230,000	596,718	366,718	$ 0.4614	$9,983,019	$ 1.5857	$34,308,784	$	$0
March 1, 2014 - June 1, 2014	250,000	596,718	346,718	$ 0.4614	$14,717,765	$ 1.5857	$50,580,755	$	$0
June 1 2014 - Jan 1 2015	400,000	596,718	196,718	$ 0.4614	$19,423,862	$ 1.5857	$66,754,264	$	$0
2015	400,000	596,718	196,718	$ 0.4729	$33,957,721	$ 1.5857	$113,856,572	$	$0
2016	400,000	596,718	196,718	$ 0.4848	$34,902,024	$ 1.5857	$114,168,508	$	$0
2017	400,000	596,718	196,718	$ 0.4969	$35,676,830	$ 1.5857	$113,856,572	$	$0
2018	400,000	596,718	196,718	$ 0.5093	$36,568,751	$ 1.5857	$113,856,572	$	$0
2019	400,000	596,718	196,718	$ 0.5220	$37,482,970	$ 1.5857	$113,856,572	$	$0
2020	400,000	596,718	196,718	$ 0.5351	$38,525,305	$ 1.5857	$114,168,508	$	$0
2021	487,500	596,718	109,218	$ 0.5485	$21,864,117	$ 1.5857	$63,213,278	$	$0
2022	575,000	596,718	21,718	$ 0.5622	$4,456,390	$ 1.5857	$12,569,984	$	$0
2023	750,000	800,000	50,000	$ 0.5762	$10,516,113	$ 1.5857	$28,939,025	$	$0
2024	837,500	1,000,000	162,500	$ 0.5906	$35,127,779	$ 1.5857	$94,309,508	$	$0
2025	1,012,500	1,250,000	237,500	$ 0.6054	$52,480,334	$ 1.5857	$137,460,366	$	$0
2026	1,187,500	1,250,000	62,500	$ 0.6205	$14,155,879	$ 1.5857	$36,173,781	$	$0
2027	1,187,500	1,250,000	62,500	$ 0.6360	$14,509,776	$ 1.5857	$36,173,781	$	$0
2028	1,187,500	1,250,000	62,500	$ 0.6519	$14,913,268	$ 1.5857	$36,272,888	$	$0
2029	1,187,500	1,250,000	62,500	$ 0.6682	$15,244,334	$ 1.5857	$36,173,781	$	$0
2030	1,187,500	1,250,000	62,500	$ 0.6850	$15,625,442	$ 1.5857	$36,173,781	$	$0
2031	1,187,500	1,250,000	62,500	$ 0.7021	$16,016,078	$ 1.5857	$36,173,781	$	$0
2032	1,187,500	1,250,000	62,500	$ 0.7196	$16,461,457	$ 1.5857	$36,272,888	$	$0
2033	1,187,500	1,250,000	62,500	$ 0.7376	$16,826,892	$ 1.5857	$36,173,781	$	$0
2034	1,187,500	1,250,000	62,500	$ 0.7561	$17,247,565	$ 1.5857	$36,173,781	$	$0
2035	1,187,500	1,250,000	62,500	$ 0.7750	$17,678,754	$ 1.5857	$36,173,781	$	$0
2036	1,187,500	1,250,000	62,500	$ 0.7943	$18,170,368	$ 1.5857	$36,272,888	$	$0
2037	1,187,500	1,250,000	62,500	$ 0.8142	$18,573,741	$ 1.5857	$36,173,781	$	$0
2038	1,187,500	1,250,000	62,500	$ 0.8345	$19,038,064	$ 1.5857	$36,173,781	$	$0
2039	1,187,500	1,250,000	62,500	$ 0.8554	$19,514,036	$ 1.5857	$36,173,781	$	$0
2040	1,187,500	1,250,000	62,500	$ 0.8768	$20,056,687	$ 1.5857	$36,272,888	$	$0
2041	1,187,500	1,250,000	62,500	$ 0.8987	$20,501,934	$ 1.5857	$36,173,781	$	$0
2042	1,187,500	1,250,000	62,500	$ 0.9212	$21,014,483	$ 1.5857	$36,173,781	$	$0
2043	1,187,500	1,250,000	62,500	$ 0.9442	$21,539,845	$ 1.5857	$36,173,781	$	$0
2044	1,187,500	1,250,000	62,500	$ 0.9678	$22,138,829	$ 1.5857	$36,272,888	$	$0
2045	1,187,500	1,250,000	62,500	$ 0.9920	$22,630,299	$ 1.5857	$36,173,781	$	$0
2046	1,187,500	1,250,000	62,500	$ 1.0168	$23,196,057	$ 1.5857	$36,173,781	$	$0
2047	1,187,500	1,250,000	62,500	$ 1.0422	$23,775,958	$ 1.5857	$36,173,781	$	$0
2048	1,187,500	1,250,000	62,500	$ 1.0683	$24,437,125	$ 1.5857	$36,272,888	$	$0
2049	1,187,500	1,250,000	62,500	$ 1.0950	$24,979,616	$ 1.5857	$36,173,781	$	$0
2050	1,187,500	1,250,000	62,500	$ 1.1224	$25,604,107	$ 1.5857	$36,173,781	$	$0
2051	1,187,500	1,250,000	62,500	$ 1.1504	$26,244,209	$ 1.5857	$36,173,781	$	$0
2052	1,187,500	1,250,000	62,500	$ 1.1792	$26,974,014	$ 1.5857	$36,272,888	$	$0
2053	1,187,500	1,250,000	62,500	$ 1.2087	$27,572,622	$ 1.5857	$36,173,781	$	$0

1/ Unit release values based upon the average cost paid by FPL for interruptible transportation capacity into Florida ($0.4614/MMBtu) during 2008. As conservative assumption, this value is assumed constant through 2014 and escalated at a rate of 2.5% per year thereafter.

2/ Unit release values based upon FGT Phase VIII Projected Maximum Tariff Recourse Rate as per Exhibit N of FGT's FERC Certificate Filing.

Attachment V B:

Projected Cost Recovery Associated with Sales of Company B Project Excess Capacity

Year	Cost Recovery for Release/Sale of Excess Capacity Utilizing Various Release Value Assumptions								
				Case A - Current Market		Case B - FGT Max Rate		Case C - No Value	
	FPL Natural Gas Fuel Requirements (MMBtu/day)	Proposed Company B Delivery Capacity [1] (MMBtu/day)	Capacity Available For Release (MMBtu/day)	Unit Release Values [2] ($/MMBtu)	Revenues from Capacity Release ($)	Unit Release Values [3] ($/MMBtu)	Revenues from Capacity Release ($)	Unit Release Values ($/MMBtu)	Revenues from Capacity Release ($)
Column	1	2	3	4	5	6	7	8	9
Source	Attachment VA, Column 1	See Footnote 1/	Col 2 - Col 1	See Footnote 2/	Col 4 * Col 3 * days in year	See Footnote 3/	Col 6 * Col 3 * days in year	Assume No Value	Col 8 * Col 3 * days
Company B Capacity Project									
Sept 1, 2012 - Dec 1, 2012	-	50,000	50,000	$0.4614	$2,099,547	$ 1.5857	$7,214,935	$	$0
Dec 1, 2012 - Jan 1, 2013	30,000	50,000	20,000	$0.4614	$286,092	$ 1.5857	$983,134	$	$0
Jan 1, 2013 - March 1, 2013	30,000	50,000	20,000	$0.4614	$544,496	$ 1.5857	$1,871,126	$	$0
March 1, 2013 - Sept 1, 2013	50,000	50,000	0	$0.4614	$0	$ 1.5857	$0	$	$0
Sept 1, 2013 - Dec 1, 2013	200,000	400,000	200,000	$0.4614	$8,398,187	$ 1.5857	$28,859,740	$	$0
Dec 1, 2013 - Jan 1, 2014	230,000	400,000	170,000	$0.4614	$2,431,783	$ 1.5857	$8,356,639	$	$0
Jan 1, 2014 - March 1, 2014	230,000	400,000	170,000	$0.4614	$4,628,231	$ 1.5857	$15,904,571	$	$0
March 1, 2014 - June 1, 2014	250,000	400,000	150,000	$0.4614	$6,367,856	$ 1.5857	$21,882,660	$	$0
June 1 2014 - Jan 1 2015	400,000	400,000	0	$0.4614	$0	$ 1.5857	$0	$	$0
2015	400,000	400,000	-	$	$0	$ 1.5857	$0	$	$0
2016	400,000	400,000	-	$	$0	$ 1.5857	$0	$	$0
2017	400,000	400,000	-	$	$0	$ 1.5857	$0	$	$0
2018	400,000	400,000	-	$	$0	$ 1.5857	$0	$	$0
2019	400,000	400,000	-	$	$0	$ 1.5857	$0	$	$0
2020	400,000	400,000	-	$	$0	$ 1.5857	$0	$	$0
2021	487,500	400,000	-	$	$0	$ 1.5857	$0	$	$0
2022	575,000	400,000	-	$	$0	$ 1.5857	$0	$	$0
2023	750,000	400,000	-	$	$0	$ 1.5857	$0	$	$0
2024	837,500	837,500	-	$	$0	$ 1.5857	$0	$	$0
2025	1,012,500	1,012,500	-	$	$0	$ 1.5857	$0	$	$0
2026	1,187,500	1,187,500	-	$	$0	$ 1.5857	$0	$	$0
2027	1,187,500	1,187,500	-	$	$0	$ 1.5857	$0	$	$0
2028	1,187,500	1,187,500	-	$	$0	$ 1.5857	$0	$	$0
2029	1,187,500	1,187,500	-	$	$0	$ 1.5857	$0	$	$0
2030	1,187,500	1,187,500	-	$	$0	$ 1.5857	$0	$	$0
2031	1,187,500	1,187,500	-	$	$0	$ 1.5857	$0	$	$0
2032	1,187,500	1,187,500	-	$	$0	$ 1.5857	$0	$	$0
2033	1,187,500	1,187,500	-	$	$0	$ 1.5857	$0	$	$0
2034	1,187,500	1,187,500	-	$	$0	$ 1.5857	$0	$	$0
2035	1,187,500	1,187,500	-	$	$0	$ 1.5857	$0	$	$0
2036	1,187,500	1,187,500	-	$	$0	$ 1.5857	$0	$	$0
2037	1,187,500	1,187,500	-	$	$0	$ 1.5857	$0	$	$0
2038	1,187,500	1,187,500	-	$	$0	$ 1.5857	$0	$	$0
2039	1,187,500	1,187,500	-	$	$0	$ 1.5857	$0	$	$0
2040	1,187,500	1,187,500	-	$	$0	$ 1.5857	$0	$	$0
2041	1,187,500	1,187,500	-	$	$0	$ 1.5857	$0	$	$0
2042	1,187,500	1,187,500	-	$	$0	$ 1.5857	$0	$	$0
2043	1,187,500	1,187,500	-	$	$0	$ 1.5857	$0	$	$0
2044	1,187,500	1,187,500	-	$	$0	$ 1.5857	$0	$	$0
2045	1,187,500	1,187,500	-	$	$0	$ 1.5857	$0	$	$0
2046	1,187,500	1,187,500	-	$	$0	$ 1.5857	$0	$	$0
2047	1,187,500	1,187,500	-	$	$0	$ 1.5857	$0	$	$0
2048	1,187,500	1,187,500	-	$	$0	$ 1.5857	$0	$	$0
2049	1,187,500	1,187,500	-	$	$0	$ 1.5857	$0	$	$0
2050	1,187,500	1,187,500	-	$	$0	$ 1.5857	$0	$	$0
2051	1,187,500	1,187,500	-	$	$0	$ 1.5857	$0	$	$0
2052	1,187,500	1,187,500	-	$	$0	$ 1.5857	$0	$	$0
2053	1,187,500	1,187,500	-	$	$0	$ 1.5857	$0	$	$0

1/ Proposed Company B delivery capacity *in initial years (2012 through 2021) set as consistent with the proposal from Company B. In all years thereafter,* capacity set as equal to FPL projected incremental demand.

2/ Unit release values based upon the average cost paid by FPL for interruptible transportation capacity into Florida ($0.4614/MMBtu) during 2008. As conservative assumption, this value is assumed constant through 2014 and escalated at a rate of 2.5% per year thereafter.

3/ Unit release values based upon FGT Phase VIII Projected Maximum Tariff Recourse Rate as per Exhibit N of FGT's FERC Certificate Filing.

Attachment VI A

Estimated Benefit of Economic Dispatch with Proposed Pipeline System in Service
(Cases A and B - Assumes Unsubscribed Capacity Released into Market)

Year	Upstream Pipeline Project / Florida EnergySecure Line Project						
	Average Unsubscribed Capacity Not Released in Secondary Market (MMBtu/day)	FPL Natural Gas Demand Served (MMBtu/day)	Average Load Factor for new capacity (%) 1/	Average Unutilized Subscribed Capacity (MMBtu/yr) 1/	Total Capacity Available for Economic Dispatch (MMBtu/yr)	Projected Unit Price of Gas into Upstream Pipeline / FPL Pipeline ($/MMBtu)	Variable Cost on Upstream Pipeline / FPL Project ($/MMBtu)
Column	1	2	3	4	5	6	7
Source	Attachment VB	FPL Base Resource Plan	See Footnote 1/	Col 2 * days in year * (1 - Col 3)	(Col 1 * days in year) + Col 4	Attachment IV, Col 12	Attachment IV, Col 17
2014		400,000	59%	60,577,700	60,577,700	$ 8.7449	$ 0.2443
2015		400,000	72%	41,242,200	41,242,200	$ 9.2445	$ 0.2571
2016		400,000	76%	35,286,000	35,286,000	$ 9.7440	$ 0.2700
2017		400,000	78%	31,997,700	31,997,700	$ 10.3435	$ 0.2852
2018		400,000	79%	30,513,700	30,513,700	$ 11.1428	$ 0.3053
2019		400,000	78%	31,584,600	31,584,600	$ 12.1420	$ 0.3302
2020		400,000	76%	34,829,500	34,829,500	$ 12.7942	$ 0.3468
2021		487,500	75%	44,484,375	44,484,375	$ 13.0490	$ 0.3539
2022		575,000	75%	52,468,750	52,468,750	$ 13.3089	$ 0.3611
2023		750,000	75%	68,437,500	68,437,500	$ 13.5740	$ 0.4216
2024		837,500	75%	76,831,250	76,831,250	$ 13.8444	$ 0.4494
2025		1,012,500	75%	92,390,625	92,390,625	$ 14.1202	$ 0.5478
2026		1,187,500	75%	108,359,375	108,359,375	$ 14.4015	$ 0.5589
2027		1,187,500	75%	108,359,375	108,359,375	$ 14.6885	$ 0.5703
2028		1,187,500	75%	108,656,250	108,656,250	$ 14.9812	$ 0.5819
2029		1,187,500	75%	108,359,375	108,359,375	$ 15.2797	$ 0.5937
2030		1,187,500	75%	108,359,375	108,359,375	$ 15.5842	$ 0.6058
2031		1,187,500	75%	108,359,375	108,359,375	$ 15.8948	$ 0.6182
2032		1,187,500	75%	108,656,250	108,656,250	$ 16.2116	$ 0.6307
2033		1,187,500	75%	108,359,375	108,359,375	$ 16.5348	$ 0.6436
2034		1,187,500	75%	108,359,375	108,359,375	$ 16.8644	$ 0.6567
2035		1,187,500	75%	108,359,375	108,359,375	$ 17.2006	$ 0.6701
2036		1,187,500	75%	108,656,250	108,656,250	$ 17.5436	$ 0.6837
2037		1,187,500	75%	108,359,375	108,359,375	$ 17.8933	$ 0.6977
2038		1,187,500	75%	108,359,375	108,359,375	$ 18.2501	$ 0.7119
2039		1,187,500	75%	108,359,375	108,359,375	$ 18.6140	$ 0.7264
2040		1,187,500	75%	108,656,250	108,656,250	$ 18.9852	$ 0.7412
2041		1,187,500	75%	108,359,375	108,359,375	$ 19.3638	$ 0.7564
2042		1,187,500	75%	108,359,375	108,359,375	$ 19.7500	$ 0.7718
2043		1,187,500	75%	108,359,375	108,359,375	$ 20.1439	$ 0.7875
2044		1,187,500	75%	108,656,250	108,656,250	$ 20.5457	$ 0.8036
2045		1,187,500	75%	108,359,375	108,359,375	$ 20.9555	$ 0.8200
2046		1,187,500	75%	108,359,375	108,359,375	$ 21.3735	$ 0.8367
2047		1,187,500	75%	108,359,375	108,359,375	$ 21.7999	$ 0.8538
2048		1,187,500	75%	108,656,250	108,656,250	$ 22.2348	$ 0.8713
2049		1,187,500	75%	108,359,375	108,359,375	$ 22.6784	$ 0.8890
2050		1,187,500	75%	108,359,375	108,359,375	$ 23.1308	$ 0.9072
2051		1,187,500	75%	108,359,375	108,359,375	$ 23.5923	$ 0.9257
2052		1,187,500	75%	108,656,250	108,656,250	$ 24.0631	$ 0.9446
2053		1,187,500	75%	108,359,375	108,359,375	$ 24.5432	$ 0.9639

Year	Variable Costs of FPL's Current Contracted FGT Service 4/					Economic Dispatch Savings vs. Contracted FGT Service			
	FGT Fuel Retention Rate (%)	Projected Henry Hub Cost of Gas ($/MMBtu) 2/	Projected Basis to FGT Zone 3 ($/MMBtu) 3/	Projected Unit Cost of Gas into FGT ($/MMBtu)	Variable (fuel) Cost on FGT Pipeline System ($/MMBtu)	Variable Service Cost Savings with New Pipeline System ($/MMBtu)	Gas Cost Savings with New Pipeline System ($/MMBtu)	Total Economic Dispatch Savings Available ($/MMBtu)	Economic Dispatch Savings Available ($/Year)
Column	8	9	10	11	12	13	14	15	16
Source	FGT Phase VIII Filing - Exhibit N	See Footnote 2/	See Footnote 3/	Col 9 + Col 10	[Col 11 / (1 - Col 8)] - Col 11	Col 12 - Col 7	Col 11 - Col 6	Col 13 + Col 14	Col 5 * Col 15
2014	3.26%	$ 8.692	$ 0.0968	$ 8.789	$ 0.2962	$0.0519	$ 0.0443	0.0962	$ 5,828,278
2015	3.26%	$ 9.192	$ 0.0968	$ 9.289	$ 0.3130	$0.0559	$ 0.0443	0.1002	$ 4,133,139
2016	3.26%	$ 9.692	$ 0.0968	$ 9.788	$ 0.3299	$0.0599	$ 0.0443	0.1042	$ 3,676,767
2017	3.26%	$ 10.291	$ 0.0968	$ 10.388	$ 0.3501	$0.0648	$ 0.0443	0.1091	$ 3,492,079
2018	3.26%	$ 11.090	$ 0.0968	$ 11.187	$ 0.3770	$0.0717	$ 0.0443	0.1160	$ 3,539,804
2019	3.26%	$ 12.069	$ 0.0968	$ 12.166	$ 0.4107	$0.0805	$ 0.0443	0.1248	$ 3,941,567
2020	3.26%	$ 12.742	$ 0.0968	$ 12.839	$ 0.4326	$0.0859	$ 0.0443	0.1302	$ 4,533,935
2021	3.26%	$ 12.997	$ 0.0968	$ 13.093	$ 0.4412	$0.0873	$ 0.0443	0.1316	$ 5,856,337
2022	3.26%	$ 13.256	$ 0.0968	$ 13.353	$ 0.4500	$0.0888	$ 0.0443	0.1331	$ 6,986,102
2023	3.26%	$ 13.522	$ 0.0968	$ 13.618	$ 0.4589	$0.0373	$ 0.0443	0.0816	$ 5,583,921
2024	3.26%	$ 13.792	$ 0.0968	$ 13.889	$ 0.4680	$0.0186	$ 0.0443	0.0629	$ 4,820,803
2025	3.26%	$ 14.068	$ 0.0968	$ 14.165	$ 0.4773	($0.0704)	$ 0.0443		$ -
2026	3.26%	$ 14.349	$ 0.0968	$ 14.446	$ 0.4868	($0.0721)	$ 0.0443		$ -
2027	3.26%	$ 14.636	$ 0.0968	$ 14.733	$ 0.4965	($0.0738)	$ 0.0443		$ -
2028	3.26%	$ 14.929	$ 0.0968	$ 15.025	$ 0.5063	($0.0755)	$ 0.0443		$ -
2029	3.26%	$ 15.227	$ 0.0968	$ 15.324	$ 0.5164	($0.0773)	$ 0.0443		$ -
2030	3.26%	$ 15.532	$ 0.0968	$ 15.629	$ 0.5267	($0.0792)	$ 0.0443		$ -
2031	3.26%	$ 15.842	$ 0.0968	$ 15.939	$ 0.5371	($0.0810)	$ 0.0443		$ -
2032	3.26%	$ 16.159	$ 0.0968	$ 16.256	$ 0.5478	($0.0829)	$ 0.0443		$ -
2033	3.26%	$ 16.482	$ 0.0968	$ 16.579	$ 0.5587	($0.0849)	$ 0.0443		$ -
2034	3.26%	$ 16.812	$ 0.0968	$ 16.909	$ 0.5698	($0.0869)	$ 0.0443		$ -
2035	3.26%	$ 17.148	$ 0.0968	$ 17.245	$ 0.5811	($0.0890)	$ 0.0443		$ -
2036	3.26%	$ 17.491	$ 0.0968	$ 17.588	$ 0.5927	($0.0911)	$ 0.0443		$ -
2037	3.26%	$ 17.841	$ 0.0968	$ 17.938	$ 0.6045	($0.0932)	$ 0.0443		$ -
2038	3.26%	$ 18.198	$ 0.0968	$ 18.294	$ 0.6165	($0.0954)	$ 0.0443		$ -
2039	3.26%	$ 18.561	$ 0.0968	$ 18.658	$ 0.6288	($0.0977)	$ 0.0443		$ -
2040	3.26%	$ 18.933	$ 0.0968	$ 19.029	$ 0.6413	($0.1000)	$ 0.0443		$ -
2041	3.26%	$ 19.311	$ 0.0968	$ 19.408	$ 0.6540	($0.1023)	$ 0.0443		$ -
2042	3.26%	$ 19.697	$ 0.0968	$ 19.794	$ 0.6670	($0.1047)	$ 0.0443		$ -
2043	3.26%	$ 20.091	$ 0.0968	$ 20.188	$ 0.6803	($0.1072)	$ 0.0443		$ -
2044	3.26%	$ 20.493	$ 0.0968	$ 20.590	$ 0.6939	($0.1097)	$ 0.0443		$ -
2045	3.26%	$ 20.903	$ 0.0968	$ 21.000	$ 0.7077	($0.1123)	$ 0.0443		$ -
2046	3.26%	$ 21.321	$ 0.0968	$ 21.418	$ 0.7217	($0.1150)	$ 0.0443		$ -
2047	3.26%	$ 21.747	$ 0.0968	$ 21.844	$ 0.7361	($0.1177)	$ 0.0443		$ -
2048	3.26%	$ 22.182	$ 0.0968	$ 22.279	$ 0.7508	($0.1205)	$ 0.0443		$ -
2049	3.26%	$ 22.626	$ 0.0968	$ 22.723	$ 0.7657	($0.1233)	$ 0.0443		$ -
2050	3.26%	$ 23.078	$ 0.0968	$ 23.175	$ 0.7810	($0.1262)	$ 0.0443		$ -
2051	3.26%	$ 23.540	$ 0.0968	$ 23.637	$ 0.7965	($0.1292)	$ 0.0443		$ -
2052	3.26%	$ 24.011	$ 0.0968	$ 24.107	$ 0.8124	($0.1323)	$ 0.0443		$ -
2053	3.26%	$ 24.491	$ 0.0968	$ 24.588	$ 0.8286	($0.1354)	$ 0.0443		$ -

1/ Capacity usage for the years 2014 through 2020 as per FPL annual gas consumption projections for RBEC and CCEC facilities. Capacity usage for the years 2021 and beyond based upon assumed 75% capacity usage load factor.

2/ Henry Hub Cost of Gas equal to price included in FPL fuel price forecast developed November 2008.

3/ Basis differential between Henry Hub and FGT Zone 3 equal to value included within FPL fuel price forecast published November 2008.

4/ FPL has large quantities of firm transportation capacity under contract with both FGT and Gulfstream. As there is a higher marginal cost associated with the use of FGT capacity than Gulfstream capacity, it is assumed that any economic dispatch activity would serve to dis higher cost FGT capacity. Thus, economic dispatch value is represented by the difference in cost between the use of the proposed project capacity and the FGT capacity under contract.

Attachment VI B

Estimated Benefit of Economic Dispatch with Proposed Pipeline System in Service
(Case C - Assumes No Release of Unsubscribed Capacity into Market)

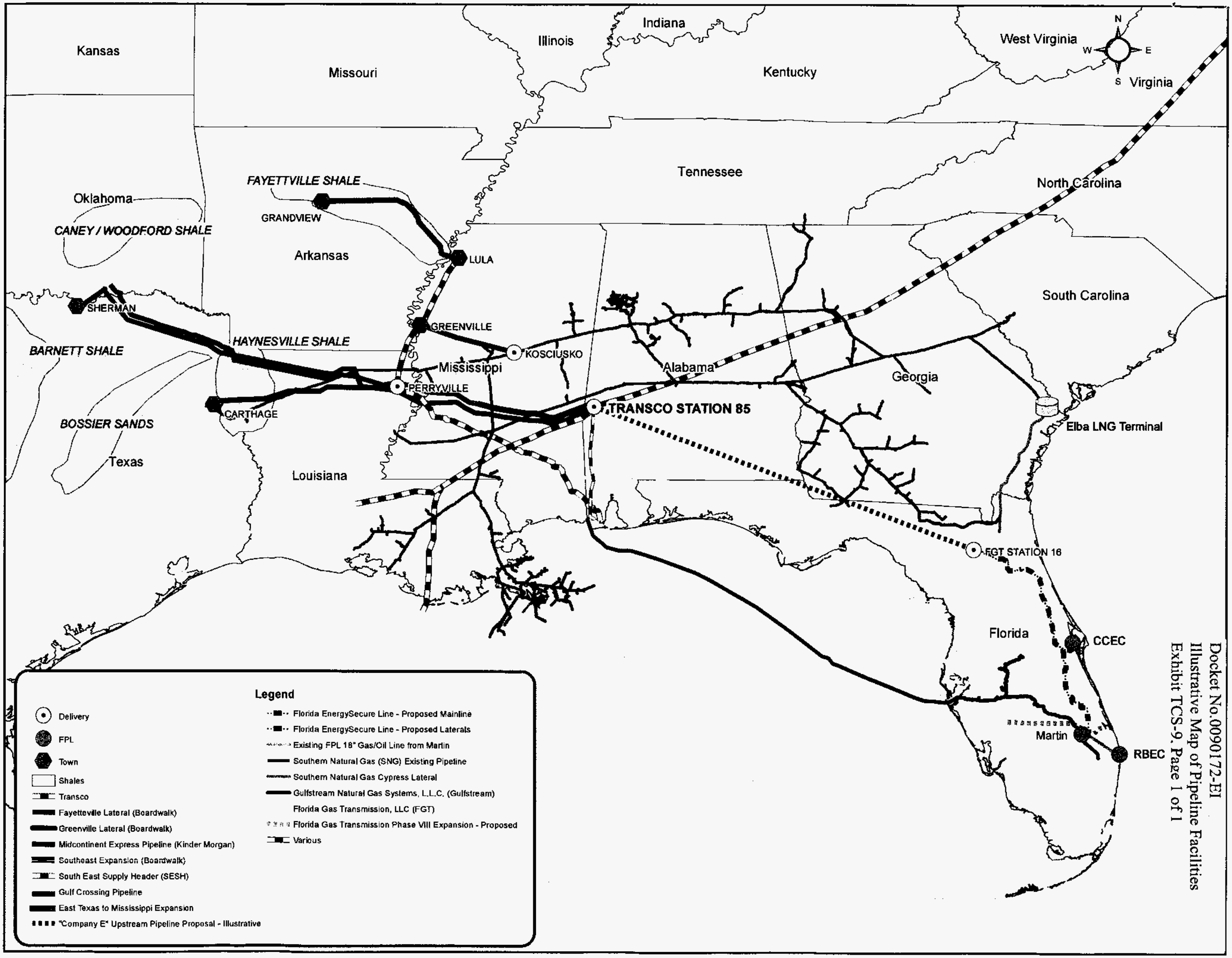
	Upstream Pipeline Project / Florida EnergySecure Line Project							Variable Costs of FPL's Current Contracted FGT Service [4]					Economic Dispatch Savings vs. Contracted FGT Service			
Year	Average Unsubscribed Capacity *Not Released* in Secondary Market (MMBtu/day)	FPL *Natural Gas* Demand Served (MMBtu/day)	Average Load *Factor for* for new capacity (%) 1/	Average *Unutilized* Subscribed Capacity (MMBtu/yr) 1/	Total Capacity *Available for* Economic Dispatch (MMBtu/yr)	Projected Unit Price of Gas into Upstream Pipeline / FPL Pipeline ($/MMBtu)	Variable Cost on Upstream Pipeline / FPL Project ($/MMBtu)	FGT Fuel Retention Rate (%)	Projected Henry Hub Cost of Gas ($/MMBtu) 2/	Projected Basis to FGT Zone 3 ($/MMBtu) 3/	Projected Unit Cost of Gas into FGT ($/MMBtu)	Variable (fuel) Cost on FGT Pipeline System [$/MMBtu]	Variable Service Cost Savings with New Pipeline System ($/MMBtu)	Gas Cost Savings with New Pipeline System ($/MMBtu)	Total Economic Dispatch Savings Available ($/MMBtu)	Economic Dispatch Savings Available ($/Year)
Column	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16
Source	No Capacity Released	FPL Base Resource Plan	See Footnote 1/	Col 2 * days in year * (1 - Col 3)	(Col 1 * days in year) + Col 4	Attachment IV, Col 12	Attachment IV, Col 17	*FGT Phase* VIII Filing - Exhibit N	See Footnote 2/	See Footnote 3/	Col 9 + Col 10	[Col 11 / (1 - Col 8)] - Col 11	Col 12 - Col 7	Col 11 - Col 6	Col 13 + Col 14	Col 5 * Col 15
2014	262,006	400,000	59%	60,577,700	156,209,789	$ 8.7449	$ 0.2443	3.26%	$ 8.692	$ 0.0968	$ 8.789	$ 0.2962	$0.0519	$ 0.0443	0.0962	$ 15,029,194
2015	196,718	400,000	72%	41,242,200	113,044,289	$ 9.2445	$ 0.2571	3.26%	$ 9.192	$ 0.0968	$ 9.289	$ 0.3130	$0.0559	$ 0.0443	0.1002	$ 11,328,875
2016	196,718	400,000	76%	35,286,000	107,284,807	$ 9.7440	$ 0.2700	3.26%	$ 9.692	$ 0.0968	$ 9.788	$ 0.3299	$0.0599	$ 0.0443	0.1042	$ 11,178,973
2017	196,718	400,000	78%	31,997,700	103,799,789	$ 10.3435	$ 0.2852	3.26%	$ 10.291	$ 0.0968	$ 10.388	$ 0.3501	$0.0648	$ 0.0443	0.1091	$ 11,328,223
2018	196,718	400,000	79%	30,513,700	102,315,789	$ 11.1428	$ 0.3053	3.26%	$ 11.090	$ 0.0968	$ 11.187	$ 0.3770	$0.0717	$ 0.0443	0.1160	$ 11,868,081
2019	196,718	400,000	78%	31,584,600	103,366,689	$ 12.1420	$ 0.3302	3.26%	$ 12.089	$ 0.0968	$ 12.186	$ 0.4107	$0.0805	$ 0.0443	0.1248	$ 12,902,034
2020	196,718	400,000	76%	34,629,500	106,828,307	$ 12.7942	$ 0.3468	3.26%	$ 12.742	$ 0.0968	$ 12.839	$ 0.4326	$0.0859	$ 0.0443	0.1302	$ 13,906,389
2021	109,218	*487,500*	75%	*44,484,375*	*84,348,984*	$ *13.0490*	$ *0.3539*	3.26%	$ *12.997*	$ *0.0968*	$ 13.093	$ *0.4412*	*$0.0873*	$ *0.0443*	*0.1316*	$ 11,104,481
2022	21,718	575,000	75%	52,468,750	60,395,839	$ 13.3088	$ 0.3611	3.26%	$ 13.256	$ 0.0968	$ 13.353	$ 0.4500	$0.0888	$ 0.0443	0.1331	$ 8,041,577
2023	50,000	750,000	75%	68,437,500	86,687,500	$ 13.5740	$ 0.4216	3.26%	$ 13.522	$ 0.0968	$ 13.618	$ 0.4589	$0.0373	$ 0.0443	0.0816	$ 7,072,966
2024	162,500	837,500	75%	76,631,250	136,106,250	$ 13.8444	$ 0.4494	3.26%	$ 13.792	$ 0.0968	$ 13.889	$ 0.4680	$0.0186	$ 0.0443	0.0629	$ 8,562,322
2025	237,500	1,012,500	75%	92,390,625	179,078,125	$ 14.1202	$ 0.5478	3.26%	$ 14.068	$ 0.0968	$ 14.165	$ 0.4773	($0.0704)	$ 0.0443		$ -
2026	62,500	1,187,500	75%	108,359,375	131,171,875	$ 14.4015	$ 0.5589	3.26%	$ 14.349	$ 0.0968	$ 14.446	$ 0.4868	($0.0721)	$ 0.0443		$ -
2027	62,500	1,187,500	75%	108,359,375	131,171,875	$ 14.6885	$ 0.5703	3.26%	$ 14.636	$ 0.0968	$ 14.733	$ 0.4965	($0.0738)	$ 0.0443		$ -
2028	62,500	1,187,500	75%	108,656,250	131,531,250	$ 14.9812	$ 0.5819	3.26%	$ 14.929	$ 0.0968	$ 15.025	$ 0.5063	($0.0755)	$ 0.0443		$ -
2029	62,500	1,187,500	75%	108,359,375	131,171,875	$ 15.2797	$ 0.5937	3.26%	$ 15.227	$ 0.0968	$ 15.324	$ 0.5164	($0.0773)	$ 0.0443		$ -
2030	62,500	1,187,500	75%	108,359,375	131,171,875	$ 15.5842	$ 0.6056	3.26%	$ 15.532	$ 0.0968	$ 15.629	$ 0.5267	($0.0792)	$ 0.0443		$ -
2031	62,500	1,187,500	75%	108,359,375	131,171,875	$ 15.8948	$ 0.6182	3.26%	$ 15.842	$ 0.0968	$ 15.939	$ 0.5371	($0.0810)	$ 0.0443		$ -
2032	62,500	1,187,500	75%	108,656,250	131,531,250	$ 16.2116	$ 0.6307	3.26%	$ 16.159	$ 0.0968	$ 16.256	$ 0.5478	($0.0829)	$ 0.0443		$ -
2033	62,500	1,187,500	75%	108,359,375	131,171,875	$ 16.5348	$ 0.6436	3.26%	$ 16.482	$ 0.0968	$ 16.579	$ 0.5587	($0.0849)	$ 0.0443		$ -
2034	62,500	1,187,500	75%	108,359,375	131,171,875	$ 16.8644	$ 0.6567	3.26%	$ 16.812	$ 0.0968	$ 16.909	$ 0.5698	($0.0869)	$ 0.0443		$ -
2035	62,500	1,187,500	75%	108,359,375	131,171,875	$ 17.2006	$ 0.6701	3.26%	$ 17.148	$ 0.0968	$ 17.245	$ 0.5811	($0.0890)	$ 0.0443		$ -
2036	62,500	1,187,500	75%	108,656,250	131,531,250	$ 17.5435	$ 0.6837	3.26%	$ 17.491	$ 0.0968	$ 17.588	$ 0.5927	($0.0911)	$ 0.0443		$ -
2037	62,500	1,187,500	75%	108,359,375	131,171,875	$ 17.8933	$ 0.6977	3.26%	$ 17.841	$ 0.0968	$ 17.938	$ 0.6045	($0.0932)	$ 0.0443		$ -
2038	62,500	1,187,500	75%	108,359,375	131,171,875	$ 18.2501	$ 0.7119	3.26%	$ 18.198	$ 0.0968	$ 18.294	$ 0.6165	($0.0954)	$ 0.0443		$ -
2039	62,500	1,187,500	75%	108,359,375	131,171,875	$ 18.6140	$ 0.7264	3.26%	$ 18.561	$ 0.0968	$ 18.658	$ 0.6288	($0.0977)	$ 0.0443		$ -
2040	62,500	1,187,500	75%	108,656,250	131,531,250	$ 18.9852	$ 0.7412	3.26%	$ 18.933	$ 0.0968	$ 19.029	$ 0.6413	($0.1000)	$ 0.0443		$ -
2041	62,500	1,187,500	75%	108,359,375	131,171,875	$ 19.3638	$ 0.7564	3.26%	$ 19.311	$ 0.0968	$ 19.408	$ 0.6540	($0.1023)	$ 0.0443		$ -
2042	*62,500*	*1,187,500*	*75%*	*108,359,375*	*131,171,875*	$ *19.7500*	$ *0.7718*	*3.26%*	$ *19.697*	$ *0.0968*	$ 19.794	$ 0.6670	($0.1047)	$ 0.0443		$ -
2043	62,500	1,187,500	75%	108,359,375	131,171,875	$ 20.1439	$ 0.7875	3.26%	$ 20.091	$ 0.0968	$ 20.188	$ 0.6803	($0.1072)	$ 0.0443		$ -
2044	62,500	1,187,500	75%	108,656,250	131,531,250	$ 20.5457	$ 0.8036	3.26%	$ 20.493	$ 0.0968	$ 20.590	$ 0.6939	($0.1097)	$ 0.0443		$ -
2045	62,500	1,187,500	75%	108,359,375	131,171,875	$ 20.9555	$ 0.8200	3.26%	$ 20.903	$ 0.0968	$ 21.000	$ 0.7077	($0.1123)	$ 0.0443		$ -
2046	62,500	1,187,500	75%	108,359,375	131,171,875	$ 21.3735	$ 0.8367	3.26%	$ 21.321	$ 0.0968	$ 21.418	$ 0.7217	($0.1150)	$ 0.0443		$ -
2047	62,500	1,187,500	75%	108,359,375	131,171,875	$ 21.7999	$ 0.8538	3.26%	$ 21.747	$ 0.0968	$ 21.844	$ 0.7361	($0.1177)	$ 0.0443		$ -
2048	62,500	1,187,500	75%	108,656,250	131,531,250	$ 22.2348	$ 0.8713	3.26%	$ 22.182	$ 0.0968	$ 22.279	$ 0.7508	($0.1205)	$ 0.0443		$ -
2049	62,500	1,187,500	75%	108,359,375	131,171,875	$ 22.6784	$ 0.8890	3.26%	$ 22.626	$ 0.0968	$ 22.723	$ 0.7657	($0.1233)	$ 0.0443		$ -
2050	62,500	1,187,500	75%	108,359,375	131,171,875	$ 23.1306	$ 0.9072	3.26%	$ 23.078	$ 0.0968	$ 23.175	$ 0.7810	($0.1262)	$ 0.0443		$ -
2051	62,500	1,187,500	75%	108,359,375	131,171,875	$ 23.5923	$ 0.9257	3.26%	$ 23.540	$ 0.0968	$ 23.637	$ 0.7965	($0.1292)	$ 0.0443		$ -
2052	62,500	1,187,500	75%	108,656,250	131,531,250	$ 24.0631	$ 0.9448	3.26%	$ 24.011	$ 0.0968	$ 24.107	$ 0.8124	($0.1323)	$ 0.0443		$ -
2053	*62,500*	*1,187,500*	*75%*	108,359,375	131,171,875	$ 24.5432	$ 0.9639	3.26%	$ 24.491	$ 0.0968	$ 24.588	$ 0.8286	($0.1354)	$ 0.0443		$ -

1/ Capacity usage for the years 2014 through 2020 as per FPL annual gas consumption projections for RBEC and CCEC facilities. Capacity usage for the years 2021 and beyond based upon assumed 75% capacity usage load factor.

2/ Henry Hub Cost of Gas equal to price included in FPL fuel price forecast published November 2008.

3/ Basis differential between Henry Hub and FGT Zone 3 *equal to value included within FPL fuel price forecast published November 2008.*

4/ FPL has large quantities of firm transportation capacity under contract with both FGT and Gulfstream. As there is a higher marginal cost associated with the use of FGT capacity than Gulfstream capacity, it is assumed that any economic dispatch activity would serve this higher cost FGT capacity. Thus, economic dispatch value is represented by the difference in cost between the use of the proposed project capacity and the FGT capacity under contract.


Kansas
Missouri
Illinois
Indiana
Kentucky
West Virginia
Virginia
N
S
E
W
Oklahoma
CANEY / WOODFORD SHALE
FAYETTVILLE SHALE
GRANDVIEW
Arkansas
LULA
Tennessee
North Carolina
South Carolina
SHERMAN
BARNETT SHALE
HAYNESVILLE SHALE
GREENVILLE
KOSCIUSKO
Mississippi
PERRYVILLE
Alabama
Georgia
CARTHAGE
TRANSCO STATION 85
BOSSIER SANDS
Texas
Louisiana
Elba LNG Terminal
FGT STATION 16
Florida
CCEC
Martin
RBEC
Legend
Delivery
FPL
Town
Shales
Transco
Fayetteville Lateral (Boardwalk)
Greenville Lateral (Boardwalk)
Midcontinent Express Pipeline (Kinder Morgan)
Southeast Expansion (Boardwalk)
South East Supply Header (SESH)
Gulf Crossing Pipeline
East Texas to Mississippi Expansion
"Company E" Upstream Pipeline Proposal - Illustrative
Florida EnergySecure Line - Proposed Mainline
Florida EnergySecure Line - Proposed Laterals
Existing FPL 18" Gas/Oil Line from Martin
Southern Natural Gas (SNG) Existing Pipeline
Southern Natural Gas Cypress Lateral
Gulfstream Natural Gas Systems, L.L.C. (Gulfstream)
Florida Gas Transmission, LLC (FGT)
Florida Gas Transmission Phase VIII Expansion - Proposed
Various

Gulf South - Southeast Expansion Shippers (per 4/09 Index of Customers)

Shipper	MDQ	Delv. Pt.
Chesapeake Energy Marketing	100,000	Transco
Chesapeake Energy Marketing	100,000	Transco
EOG Resources	100,000	Transco
EOG Resources	200,000	Destin Gulfstream
EOG Resources	50,000	Destin FGT
Oneok Energy Resources	100,000	Transco
Enerquest	10,000	Destin Gulfstream
Southeast Expansion Total	660,000	

Gulf Crossing Shippers Utilizing Gulf South Capacity Lease

(per 11/21/08 Neg. Rate Agmt. Filing in Docket No. RP09-61-001)

Shipper	MDQ	Delv. Pt.
Antero Resources Corp	20,000	Transco
Antero Resources Corp	10,000	Transco
Antero Resources Corp	10,000	Transco
Conectiv Energy Supply	10,000	Transco
Devon Gas Services	50,000	Transco
Devon Gas Services	600,000	Transco
Devon Gas Services	50,000	Transco
Enterprise Products	200,000	Transco
BP Energy Company	150,000	Transco
Gulf Crossing Total	1,100,000	

Midcontinent Express Shippers

(sourced from Neg. Rate filing made on 2/17/2009 in Docket No. CP08-6)

Shipper	MDQ	Delv. Pt.
Chesapeake Energy Marketing	300,000	Transco
Conectiv Energy Supply	10,000	Transco
Enerfin Resources	7,000	CGT
Enjet	15,000	CGT
EOG Resources	100,000	Transco
Gavilon	25,000	CGT
Iberdola Renewables	30,000	Transco
JW Gathering	30,000	Transco
Newfield Exploration	225,000	CGT/TGT
Newfield Exploration	30,000	CGT/TGT
Newfield Exploration	20,000	CGT/TGT
Newfield Exploration	35,000	CGT/TGT
Newfield Exploration	40,000	CGT/TGT
OGE Resources	100,000	Transco
Quicksilver Resources	25,000	Transco
Unit Petroleum	15,500	Transco
XTO Petroleum	350,000	Transco

Total (All Pipes) to Transco Station 85	***2,460,500***

Marginal Cost to Transport Supplies from Perryville to Transco Station 85

Assumed Value of Compressor Fuel Gas at Perryville (average 2014 price per FPL forecast) *$8.69 per MMBtu*

Route 1 - MidContinent Express Pipeline (MEP) Variable Transportation Costs				
MEP (Variable Cost to Transport Supplies from Field Points to Perryville)				
Fuel Rate Zone 1 Retention Percentage		0.54%	$0.0472	$0.0472
MEP Unnacounted For Retention Percentage		0.15%	$0.0131	$0.0131
MEP FTS Commodity Rate	$	0.0013	$0.0013	$0.0013
Total Variable Cost via MEP to Perryville			$0.0615	$0.0615
MEP (Variable Cost to Transport Supplies from Field Points to Transco Station 85)				
Fuel Rate Zone 1 Retention Percentage		0.54%	$0.0472	$0.0472
Fuel Rate Zone 2 Retention Percentage		0.14%	$0.0122	$0.0122
MEP Unnacounted For Retention Percentage		0.15%	$0.0130	$0.0130
MEP FTS Commodity Rate	$	0.0013	$0.0013	$0.0013
Total Variable Cost via MEP to Transco Station 85			$0.0737	$0.0737
Marginal transport cost to transport supplies to Station 85 vs. to Perryville			***$0.0122***	***$0.0122***
Route 2 - Gulf South (East TX to Missississippi and Southeast Expansion Projects) Variable Transportation Costs				
Boardwalk (Variable Cost to Transport Supplies from Field Points to Perryville)				
Fuel and L&U Rate		1.60%	$0.1413	$0.1413
Commodity (Zone 1 to Zone 2)		0.0064	$0.0064	$0.0064
Total Variable Cost via Boardwalk to Perryville			$0.1477	$0.1477
Boardwalk (Variable Cost to Transport Supplies from Field Points to Transco Station 85)				
Fuel and L&U Rate		1.60%	$0.1413	$0.1413
Commodity (Zone 1 to Zone 3)		0.0086	$0.0086	$0.0086
Total Variable Cost via Boardwalk to Perryville			$0.1499	$0.1499
Marginal transport cost to transport supplies to Station 85 vs. to Perryville			***$0.0022***	***$0.0022***
Route 3 - Gulf Crossing (using Gulf Crossing Capacity Lease on Gulf South Southeast Expansion) Variable Transportation Costs				
Gulf Crossing (Variable Cost to Transport Supplies from Field Points to Perryville)				
Gulf Crossing Fuel and L&U Rate		1.00%	$0.0878	$0.0878
Gulf Crossing Commodity Rate		0.0037	$0.0037	$0.0037
Total Variable Cost via Gulf Crossing to Perryville			$0.0915	$0.0915
Gulf Crossing (Variable Cost to Transport Supplies from Field Points to Transco Station 85)				
Gulf Crossing Fuel and L&U Rate		1.00%	$0.0878	$0.0878
Gulf Crossing Commodity Rate		0.0037	$0.0037	$0.0037
Incremental Fuel Retention Rate for service on Southeast Expansion Capacity Lease		0.54%	$0.0472	$0.0472
Incremental Commodity Rate for service on Southeast Expansion Capacity Lease		0.0046	$0.0046	$0.0046
Total Variable Cost via Gulf Crossing to Perryville			$0.1433	$0.1433
Marginal transport cost to transport supplies to Station 85 vs. to Perryville			***$0.0518***	***$0.0518***

Southeast Supply Header Customer Listing
[Sourced from Neg. Rate Section of SESH Tariff (Tariff Sheets 21 through 21G)]

Shipper	Rate Schedule	Contract Number	MDQ (Dth/day)
EOG RESOURCES, INC.	FTS	84005	50,000
FLORIDA POWER & LIGHT CO	FTS	84001	400,000
FLORIDA POWER & LIGHT CO	FTS	84002	100,000
FLORIDA POWER CORPORATION D/B/A PROGRESS ENERGY FLORIDA	FTS	84006	150,000
FLORIDA POWER CORPORATION D/B/A PROGRESS ENERGY FLORIDA	FTS	84007	50,000
SOUTHERN COMPANY SERVICES INC	FTS	84004	175,000
TAMPA ELECTRIC COMPANY	FTS	84003	20,000
Subtotal - End Use Shippers Capacity MDQ			895,000
Subtotal - Producer Shippers (EOG) Capacity MDQ			50,000
Total Contract MDQ			**945,000**

Projected Delivered Cost of Gas Supplies to FGT/Gulfstream via Perryville Hub

Perryville Basis Range			($0.0900)	($0.1400)
Cost of Service on SESH				
Reservation Charge (Current FPL Negotiated Rate)			$0.2750	$0.2750
Total Fixed Cost			$0.2750	$0.2750
Fuel Rate		0.70%	$0.0613	$0.0613
Commodity	$	0.0045	$0.0045	$0.0045
Total Marginal Cost			$0.0658	$0.0658
Total Cost			$0.3408	$0.3408
Value at FGT/Gulfstream (Perryville + Total Cost)			$0.2508	$0.2008