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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2	FLORIDA POWER & LIGHT COMPANY								
3	REBUTTAL TESTIMONY OF TIMOTHY C. SEXTON								
4	DOCKET NO. 090172-EI								
5	JULY 2, 2009								
6									
7	Q.	Please state your	name and business address.						
8	A.	My name is Timothy C. Sexton. I am Vice President of Gas Supply Consulting,							
9		Inc. My business address is 14811 St. Mary's, Suite 175, Houston, TX 77079.							
10	Q.	Did you previously submit direct testimony in this proceeding?							
11	А.	Yes.							
12	Q.	Are you sponsorin	ng any rebuttal exhibits in this case?						
13	A.	Yes. I am sponsor	ing the following rebuttal exhibits:						
14		• TCS-8	Updated Gas Cost Savings Analysis						
15		• TCS-9	Illustrative Map of Pipeline Facilities						
16		• TCS-10	Capacity Holders on Pipelines Upstream of Transco Station						
17			85						
18		• TCS-11	Marginal Cost to Transport to Transco Station 85						
19		• TCS-12	Capacity Holders on Southeast Supply Header						
20		• TCS-13	Total Cost to Transport from Perryville to FGT Mobile Bay						
21			Area						

1	Q.	what is the purpose of your reduttal testimony?
2	A.	The purpose of my rebuttal testimony is to comment on the testimony of Florida
3		Gas Transmission Company, LLC ("FGT") witnesses Michael T. Langston and
4		Benjamin Schlesinger. Specifically, I will address the following issues:
5		• Economic Analysis update incorporating FGT's March 18, 2009 proposal
6		• FPL's methodology for developing its long range forecast of natural gas
7		prices
8		• Liquidity of Perryville Hub natural gas supplies available to FGT versus
9		those available to Transco Station 85 and the Florida EnergySecure Line
10		project; and
11		• Appropriate cost for FGT shippers to directly access supplies at Transco
12		Station 85.
13		
14		SUMMARY
15		
16	Q.	Please summarize your rebuttal testimony.
17	A.	With respect to FGT's updated March 18, 2009 proposal, an Updated Gas Cost
18		Savings Analysis reveals that the Florida EnergySecure Line project has superior
19		economic results for FPL's customers when compared with the FGT (Company
20		B) project alternative based upon FGT's proposal.
21		
22		Next, as to the liquidity of supplies at Transco Station 85 versus supplies into
23		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.

8

9 With respect to capacity from Transco Station 85 to FGT near Mobile Bay, 10 existing low-cost capacity is scarce and is not likely to be available to support 11 FPL's Modernization projects. As a result, FPL appropriately utilized new 12 construction costs as a proxy to develop a \$0.20 per MMBtu rate applicable to 13 transporting gas supplies from Transco Station 85 to the FGT/Company B project.

14

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

- 1
- 2

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?

8 Α. No I did not. The March 18, 2009 proposal received from FGT was the fourth 9 proposal received by FPL from FGT and was received after my direct testimony 10 and associated exhibits were substantially completed. As this proposal was 11 unsolicited as well as the fourth response submitted by FGT, FPL had no way of 12 knowing if additional unsolicited responses would be forthcoming from FGT 13 prior to the date that the testimony was to be filed. As such, FPL made the 14 decision to complete the testimony and exhibits as substantially drafted based 15 upon the prior (January 12, 2009) proposal received from FGT. Consequently, 16 prior to filing my direct testimony in this proceeding, I did not examine the March 17 18, 2009 proposal as a part of my direct testimony and it was not included in the 18 Gas Cost Savings Analysis therein.

19 Q. Have you now developed an Updated Gas Cost Savings Analysis
 20 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.

1Q.In addition to updating the analysis to incorporate FGT's March 18, 20092proposal rather than the January 12, 2009 proposal, did you make any other3adjustments in the Updated Gas Cost Savings Analysis versus the Gas Cost4Savings Analysis filed with your Direct Testimony?

- 5 A. Yes. In order to account for changes in market conditions from the time of the 6 evaluation presented in my direct testimony to the present time, I have made 7 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.

2

Q.

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

Yes. Consistent with my original Gas Cost Savings Analysis, I have included 3 Α. three revenue assumptions associated with off system capacity sales based upon 4 capacity valuations consistent with those supporting the original Gas Cost Savings 5 Analysis. As such, the Updated Gas Cost Savings Analysis identified as Case A 6 incorporates an assumption that FPL receives revenues from the off system sale of 7 excess capacity equal to the average value paid for capacity on the secondary 8 9 market by FPL during 2008. The Updated Gas Cost Savings Analysis identified 10 as Case B incorporates an assumption that FPL receives revenues associated with 11 the off system sale of excess capacity equal to the maximum tariff rate associated 12 with the transportation capacity in FPL's portfolio that has the highest 13 corresponding tariff rate (FGT's proposed Phase VIII expansion maximum tariff 14 recourse rate). Finally, as a worst case assumption, the Updated Gas Cost Savings 15 Analysis identified as Case C incorporates an assumption that there is no revenue 16 associated with the off system sale of excess capacity.

17 Q. Did the results of the Updated Gas Cost Savings Analysis favor the Florida
 18 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.

8 Q. On Page 12 of his testimony, FGT witness Langston states that FGT's cost 9 would have been reduced by an approximate \$132 million if FGT had known 10 of the availability of the FPL-owned dual-fuel pipeline from the Martin Plant 11 to the 45th Street Terminal near the Riviera Plant. Do you agree with this 12 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.

1	Q.	Have you analyzed the economics of FGT's March 18, 2009 proposal taking
2		into account both FGT's alleged costs savings and FPL's costs associated
3		with potential use of the existing FPL-owned dual-fuel pipeline?
4	Α.	Yes. I conducted such an analysis using the same approach discussed in my
5		direct testimony. Consistent with the results cited by FPL witness Enjamio in his
6		rebuttal testimony, the results of my analysis continue to favor the Florida
7		EnergySecure Line alternative versus the FGT proposed alternative.
8		
9		NATURAL GAS PRICE FORECASTING METHODOLOGY
10		
11	Q.	Do you agree with FGT witness Schlesinger's assertion on Page 9 of his
12		testimony that FPL's economic assumptions as to future gas supply prices
13		are not reasonable for planning purposes?
13 14	A.	are not reasonable for planning purposes? No. I do not. As explained in detail in the rebuttal testimony of FPL witness
13 14 15	A.	are not reasonable for planning purposes?No. I do not. As explained in detail in the rebuttal testimony of FPL witnessSharra, the economic assumptions utilized by FPL in developing forecasts of
13 14 15 16	A.	are not reasonable for planning purposes?No. I do not. As explained in detail in the rebuttal testimony of FPL witnessSharra, the economic assumptions utilized by FPL in developing forecasts offuture gas supply prices were based upon market conditions at the time that the
13 14 15 16 17	A.	 are not reasonable for planning purposes? 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
 13 14 15 16 17 18 	A.	 are not reasonable for planning purposes? 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
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 13 14 15 16 17 18 19 20 21 	A.	are not reasonable for planning purposes?No. I do not. As explained in detail in the rebuttal testimony of FPL witnessSharra, the economic assumptions utilized by FPL in developing forecasts offuture gas supply prices were based upon market conditions at the time that theforecast was developed. Further, with respect to futures prices and rates ofescalation, the forecast took into account third party projections from highlyreputable sources (the PIRA Energy Group, the Energy InformationAdministration of the US Department of Energy and NYMEX forward pricecurves). As such, I believe that the forecast is reasonable for planning purposes in

1		LIQUIDITY AT FGT – MOBILE BAY AREA
2		VERSUS TRANSCO STATION 85
3		
4	Q.	FGT witnesses Schlesinger and Langston assert in their testimony that
5		FGT's proposal, with receipts in and around Mobile Bay is superior to the
6		Florida EnergySecure Line/Company E project with receipts at Transco
7		Station 85. Based upon this assertion, the FGT witnesses contend that FGT's
8		system in the Mobile Bay area rather than FPL's selection of Transco Station
9		85 would be a superior location for the commencement of the proposed
10		facilities. Do you agree with this contention?
11	A.	No. I do not. In addition to providing a superior economic result for FPL's
12		customers than the FGT proposal, the Florida EnergySecure Line project also
13		meets FPL's goal of increasing supply diversity in its portfolio whereas the FGT
14		proposal does not provide this diversification in the supply base.
15		
16		As described in detail on Page 20 of my direct testimony, with the initiation of its
17		capacity contract on FGT's Phase VIII project, approximately 1.4 Bcf/day of
18		FPL's 2.0 Bcf/day of firm natural gas transportation capacity will be sourced from
19		FGT and Gulfstream points in the Mobile Bay Area. Recognizing that traditional
20		supply sources into the Mobile Bay area are in decline, FPL has been active in
21		diversifying its supply sourcing in this area. In fact, FPL has entered into a
22		capacity contract with Southeast Supply Header (SESH) providing for
23		0.5 Bcf/day of pipeline capacity from Perryville into its capacity on FGT and

1 Gulfstream. Further, FPL has been actively discussing potential additional 2 capacity alternatives upstream of FGT and Gulfstream in support of both its existing capacity and its Phase VIII capacity rights. 3 4 With this said, as current transportation contracts will require FPL to source 5 approximately 70% of its gas supplies in the Mobile Bay area (1.4 Bcf/day out of 6 7 about 2.0 Bcf/day), sourcing additional supplies at this location via the FGT 8 system would be contrary to FPL's goal of diversifying its natural gas supply 9 portfolio. In contrast, sourcing incremental gas supply needs at the Transco 10 Station 85 location will enable FPL to diversify its portfolio of natural gas supply 11 beyond the current concentration in the Mobile Bay area. 12 13 Consequently, I believe that FPL has made the correct decision in targeting 14 Transco Station 85 as the supply source to meet its incremental natural gas 15 demand requirements. On Pages 25 and 26 of his direct testimony, FGT witness Langston states that 16 **Q**. 17 "the market prices for gas at the Perryville Hub would provide better 18 netbacks to producers as compared to the expected pricing at Transco 19 Station 85." Witness Langston further states that "once all gas demand at 20 this location is met, then gas would move to other markets, such as to 21 planned interconnects at Transco Station 85." Do you agree with witness 22 Langston's assertion that producers will have a preference to deliver gas to 23 markets at the Perryville Hub versus delivering to Transco Station 85?

No. I do not. As mentioned on Pages 21 through 24 of my direct testimony, in the 1 Α. past year three new pipeline alternatives designed to transport unconventional 2 supplies to the Perryville area and beyond to Transco Station 85 have been placed 3 into service. These pipelines include the (i) MidContinent Express Pipeline 4 (MEP); (ii) Gulf South East Texas to Mississippi and Southeast Expansion 5 6 Projects and (iii) Gulf Crossing Pipeline which, utilizing Gulf Crossing's 7 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 8 9 TCS-9 is a map depicting the locations of these pipelines to Transco Station 85 10 with respect to the Florida natural gas infrastructure.

11

12 It is important to note that the bulk of the new transportation capacity on these 13 pipelines is held by natural gas producers and aggregators (collectively, I will 14 refer to them as "producers") in the form of firm gas transportation agreements 15 with primary delivery point rights to Transco Station 85. In fact, as illustrated in 16 Exhibit TCS-10, about 2.5 Bcf/day of the approximate 3.0 Bcf/day of capacity on 17 these three systems is held under firm transportation agreements by producers 18 with primary delivery point rights to Transco near its Compressor Station 85. The 19 simple fact that these producers have entered long term firm transportation 20 contracts to transport unconventional supplies to Transco Station 85 indicates that 21 these producers will be ready, willing and able to deliver and sell supplies to this 22 location.

1Q.Do you agree with FGT witness Langston's assertion on Pages 25 and 26 of2his testimony that "given the transportation cost from the Perryville area to3Transco Station 85, it appears that the market prices for gas at the Perryville4Hub would provide better netbacks to producers as compared to the5expected 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.

13

14 More specifically, the fixed reservation fee costs of the transportation capacity 15 held by the producers from the unconventional supply sources to Transco Station 16 85 will be paid regardless of whether the producers utilize this capacity to move 17 the unconventional supplies to Perryville or to the primary contract delivery point 18 of Transco Station 85. As such, these fixed reservation fees are "sunk costs" and 19 will typically be set aside by the producers in making comparisons of netback 20 calculations for sales to a given location. In other words, if a producer is 21 committed to paying a fixed reservation fee for pipeline capacity to Transco 22 Station 85, that cost cannot be considered in a marginal netback analysis in 23 determining the best location to sell gas.

If, as witness Langston claims on lines 15 to 18 of Page 25 of his testimony, the 1 value of gas at Transco Station 85 carries a \$0.0567 to \$0.1067 per MMBtu 2 premium over the value of gas at Perryville, even if this premium is not as large 3 as the sunk cost of capacity, as long as this premium exceeds the marginal 4 variable cost to access this market, the producer will still have a preference to sell 5 the gas at Transco Station 85 rather than at Perryville to take advantage of this 6 premium. To summarize, the producer will not forgo the incremental revenue 7 associated with the higher value Transco Station 85 market simply because it is 8 9 not sufficient to cover the sunk costs paid regardless of where the gas is sold.

10Q.Have you developed a marginal netback analysis that can be utilized to11illustrate the value to a producer holding capacity on the aforementioned12three pipelines of selling gas supplies at Transco Station 85 versus doing so at13Perrvville?

14 A. Yes. I have. As discussed, the only costs relevant to a producer in determining 15 the marginal netback value of gas sales to a given location are (a) the sales price 16 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 17 18 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 19 20 per MMBtu on the Gulf South System and \$0.0518 per MMBtu on the Gulf 21 Crossing system.

1	Next, on Page 25 of his testimony, FGT witness Langston states that basis swap								
2	prices indicate that the value of gas sold at Perryville over the next 42 month								
3	period is approximately \$0.09 to \$0.14 per MMBtu below the Henry Hub price								
4	whereas gas at Transco Station 85 during this timeframe is currently priced at								
5	approximately \$0.0333	below the Henry	Hub price. As such	, per FGT witness					
6	Langston's testimony, the market value of gas at Perryville is approximately								
7	\$0.0567 per MMBtu to	5 \$0.1067 per MM	Btu below the mark	et value for gas at					
8	Transco Station 85	· · · · · · · · · · · · · · ·		0					
0	Tailseo Station 85.								
9									
10	The following table illu	astrates the results of	of a simple netback a	nalysis, as viewed					
11	from the producer's per	rspective based upor	n these price differer	tials and marginal					
12	cost difference to transp	port supplies to Perr	yville versus to Tran	sco Station 85.					
13									
14 15		MEP	Gulf <u>Crossing</u>	Gulf <u>South</u>					
16	Basis to Perryville	(\$0.09) – (\$0.14)	(\$0.09) – (\$0.14)	(\$0.09) - (\$0.14)					
17	Basis to Transco St 85	<u>(\$0.0333)</u>	(\$0.0333)	<u>(\$0.0333)</u>					
18	Incremental Value at 85	(\$0.0567) – (\$0.1067)	(\$0.0567) – (\$0.1067)	(\$0.0567) – (\$0.1067)					
19	Marginal Cost to St 85	<u>\$0.0122</u>	<u>\$0.0518</u>	<u>\$0.0022</u>					
20	Netback Premium at St 85	\$0.0445 - \$0.0945	\$0.0049 - \$0.0549	\$0.0545 - \$0.1045					
21									
22	As illustrated in the tabl	e, in every situation	, when sunk costs ar	e properly ignored					
23	in the netback analys	is, the producers	will obtain a netb	ack premium by					
24	delivering to Transco S	station 85 versus Pe	erryville on these pi	pelines. As such,					
25	with marginal netbacks	for shippers on the	e MEP, Gulf Crossir	ng 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?

8 A. No. I do not. As stated in FGT witness Langston's testimony, the FGT and 9 Gulfstream pipeline systems can receive supplies from the Perryville Hub either 10 (a) through SESH or (b) via the Gulf South capacity lease on the Destin Pipeline 11 system. FGT witness Langston fails to provide the whole story however, with 12 respect to the quantity of this capacity that is potentially available to serve FPL 13 markets.

14

15 First, the Gulf South capacity lease is for a maximum capacity of only 260,000 16 MMBtu/day. Perhaps more importantly, while SESH has a maximum capacity of 17 1 Bcf/day, as illustrated in Exhibit TCS-12, approximately 90% of the capacity on 18 SESH is under contract to end use markets with about 5% under contract to a 19 producer and about 5% as of yet unsold. These end use capacity holders, such as 20 FPL, have contracted for this capacity to serve their existing firm markets under 21 peak day conditions. Thus, this capacity will not be available to provide supply to 22 incremental FPL markets under peak day conditions. If one excludes this "end 23 use held" SESH capacity from the total capacity available to deliver Perryville

1 supplies to FGT and Gulfstream in the Mobile Bay area, a total of only about 2 360,000 MMBtu/day of capacity (260,000 MMBtu/day held by producers on Gulf 3 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 4 demands of end use markets. In comparison to this total available capacity to 5 6 access Perryville sources from FGT/Gulfstream near Mobile Bay of 360,000 7 MMBtu/day, the combined capacity available via the three pipeline routes to Transco Station 85 (MEP, Gulf Crossing and Boardwalk's Southeast Expansion) 8 9 is approximately 3 Bcf/day with the vast majority of this capacity held by 10 producer shippers.

11

12 It is also important to consider that, as pointed out in my direct testimony, FGT's 13 Phase VIII project is designed to source an incremental 821,000 MMBtu/day from 14 Mobile Bay area supply sources. In addition, Gulfstream's recent Phases 3 and 4 15 expansion projects also were designed to source supplies from the Mobile Bay 16 Area. In the aggregate, after the installation of FGT's Phase VIII project, 17 Gulfstream's and FGT's shippers will rely upon approximately 3.0 Bcf/day of 18 receipts in and around the Mobile Bay Area.

19

20 Recognizing that traditional Mobile Bay supply sources are in decline coupled 21 with the fact that FGT's Phase VIII shippers will need to obtain supplies in this 22 same area sufficient to meet 821,000 MMBtu/day of incremental Phase VIII 23 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.

3

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.

8 Q. Do the investment decisions made by producers over the past several years 9 provide any indication of the potential liquidity of Perryville supplies at 10 Transco Station 85 versus at Mobile Bay via the FGT and/or Gulfstream 11 Systems?

12 Yes. As mentioned previously in my rebuttal testimony, three new pipelines with Α. a combined capacity of about 3 Bcf/day have recently been constructed from 13 unconventional sources to the Transco Station 85 location. As also discussed, and 14 15 as illustrated in Exhibit TCS-10, the capacity on these three pipelines is primarily 16 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 17 18 investment required, through the execution of long term capacity contracts, to support the construction of these pipelines from unconventional sources to 19 20 Transco Station 85 provides a strong indication that these producers view the 21 Transco Station 85 market as a desirable high value liquid market for 22 unconventional supplies.

As a result of this view of the market at Transco Station 85, the producers have 1 made the investment required to make 3 Bcf of unconventional supplies available 2 at this location. This is not the case with respect to Mobile Bay. In contrast to 3 Transco Station 85, the producers have not made substantial investments to 4 transport unconventional supplies to FGT and Gulfstream in the Mobile Bay area. 5 In fact, the one large scale pipeline that was built to transport unconventional 6 supplies to the Mobile Bay area in the past few years, the SESH pipeline, was 7 constructed based upon capacity contracts entered into primarily by the end use 8 market, including FPL who was the anchor shipper for the SESH project. These 9 10 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 / 11 12 Gulfstream market in and around Mobile Bay.

13

14 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 15 16 substantial investments in upstream capacity whereas the producers have been willing to make the investments required to make these supplies available at 17 18 Transco Station 85. In contrast to the producers willingness to make the 19 investments required to make supplies available at Transco Station 85, past 20 history suggests that if FPL were to contract for additional capacity on FGT with 21 receipt point rights at Mobile Bay, it is very likely that FPL will be forced to 22 make the incremental capacity investment required to solve supply issues at 23 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.

10

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.

16

17 Consequently, an analysis of the cost for FPL to obtain incremental gas supplies 18 into the FGT system from Perryville would have to include the total all-in cost of 19 expansion capacity from Perryville to FGT. These costs will include (a) the value 20 of gas supplies at Perryville; (b) fixed costs associated with incremental capacity 21 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.

8

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.

16

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.

1		APPROPRIATE COST TO PROVIDE FGT SYSTEM WITH DIRECT
2		ACCESS TO SUPPLIES AT TRANSCO STATION 85
3		
4	Q.	FGT witness Schlesinger on Page 15 of his direct testimony and FGT witness
5		Langston on Pages 20 and 21 of his direct testimony reference capacity made
6		available via an open season solicitation by Transco from Transco Station 85
7		to FGT and/or Gulfstream at a current tariff recourse rate of approximately
8		\$0.09 per MMBtu. Is this \$0.09 per MMBtu rate quoted by the witnesses a
9		predetermined fixed rate?
10	А.	No. With respect to rates in its open season process, Transco did not provide a
11		guarantee that the ultimate contract rate would be \$0.09 per MMBtu. Rather, the
12		language in the open season documents (documents attached as Exhibit BSA-4 to
13		FGT witness Schlesinger's testimony) was as follows:
14 15 16 17 18 19 20 21 22		"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"
23		Thus, as outlined in Transco's open season documents, there is no certainty as to a
24		fixed \$0.09 per MMBtu rate referenced in the FGT witness testimonies. Rather,
25		statements are made in Transco's open season documents that the capacity will be
26		sold at the maximum tariff rate as such rate may change from time to time, and
27		that if final design and cost of the Expansion exceeds the maximum tariff rate for
28		this haul, then the maximum rates will be based upon the incremental cost of the

1		Expansion (emphasis added). As such, there is no certainty that the ultimate rate
2		for this capacity will be the current tariff rate of \$0.09 per MMBtu.
3	Q.	Is the capacity on Transco's system from Transco Station 85 to FGT and
4		Gulfstream (quoted by FGT witnesses Langston and Schlesinger as \$0.09 per
5		MMBtu capacity) likely to be available to serve the FPL Modernizations?
6	A.	No. Perhaps more important than the rate uncertainty associated with this
7		capacity, as noted in the rebuttal testimony of FPL witness Sharra, as a result of
8		the recent Transco open season, Transco has indicated that they have interested
9		parties in negotiations for the remaining 550,000 MMBtu per day of capacity on
10		this line. As such, the existing lateral capacity likely will not be available to serve
11		the Modernization Projects.
12	Q.	Do you believe that the \$0.20 per MMBtu rate that you developed as a proxy
13		to represent the cost to transport gas from Transco Station 85 to FGT near
14		Mobile Bay in your direct testimony is still appropriate?
15	A.	Yes. In light of the fact that the Transco capacity is likely to be fully subscribed
16		as a result of its open season process, any new capacity from Transco Station 85
17		to FGT used to serve FPL's Modernization Projects will likely be priced based
18		upon the cost to install new facilities required to transport this gas. As such, the
19		\$0.20 per MMBtu rate, developed based upon the cost of new facilities from
20		Transco Station 85 to FGT near Mobile Bay remains an appropriate proxy to
21		represent the cost to transport gas from Transco Station 85 to EGT near Mobile
5 I		represent the cost to transport gas from fransco Station 65 to FOT hear woolie

- 1 Q. Does this conclude your rebuttal testimony?
- 2 A. Yes.

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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	\$7 57
Case C	 (a) Excess capacity retained by FPL. (b) Excess and Underutilized capacity economically dispatched by FPL to FPL Plants. 	\$6,672	\$123

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

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Summary Comparative Cost Analysis Case A - Excess Capacity Valued at 2008 Market Value

	Company & Proposal					Unstriam Pipelice Project - Florida France Secure Line Project 1/						
1								Clini gyancare L	ane riogect ()	·		
						Annual Florida	Annual Cost of				Potential Savings	Florida Foemu
			Value of		Dennand Charges	EnergySecure	Fuel Gas	Upstream	Value of		Avecutiated with	Sectors Line ve
	Demand Charges	Annual Cost of	Capacity	Nat Gas	on Upstream	Line Revenue	Retained (Pipeline Project	Capacity	Net Gan	Foonanie	Company & Net
	to Company B	Fuel Retention	Release Credits	Transport Costs	Pipeline Project	Requirements	Consumed	Commodity	Reinage	Transport Coets	Dispatch Activity	Sealoge
Year	(\$/Y48r)	Gast (\$/Year)	[[\$/Year)	(\$/Ymr)	(S/Year)	(\$/Year)	(S/Year)	Charges (S/Year)	Credits (S/Yeer)	(S/Year)	(S/Yand	(SiVeer)
Column	1	2	3	4	6	6	7			16	14	(01100)
1				Column 1 +				<u> </u>		Sum of	······································	Column 4 -
	4 Mar 1 Mar 1 1 1	ACCICICATION IL	Attication	Column 2 +		Attachment BIA,	Attacionent IV,	Attachment IV,	Attachment	Columns 5	Attachment VI A.	Column 10 +
adurce		GOINE	VIS, COIS	Column 3	Atlantment #B	Column 6	Cal 13	Col 16	VA, Col 5	through \$	Col 18	Column 11
2012	3 9,924,700	3	(\$2,385,539)	\$ 7,539,061		\$429,102			50		\$.	
2013	5 105,254,540	3 10,111,184	(311,3/4,48/)	\$ 107,991,245		\$21,083,575			\$0		s -	
2015	C 187 735 00F	3 21,490,(2) 5 35 0 (5 obt)	(357,787,231)	\$ 257,435,467		\$290,651,119			(\$44,124,646)		\$ 5,628,276	
2015	5 267,743,898	5 33,040,958	50	5 303,372,967		\$280,759,254			(\$33,957,721)		\$ 4,133,139	
2017	\$ 247 735 000	5 49 404 697	N	\$ 305,312,565		\$259,255,843			(\$34,902,024)		\$ 3,675,767	
2018	307 735 009	a 43,404,027	30	1 311,130,825		\$258,489,524			(\$35,576,630)		\$ 3,492,079	
2010	4 207,720,000	0 47,307,421	\$0	\$ 315,093,419		\$246,394,967			(\$36,565,751)		\$ 3,539,604	
2020	\$ 348 450 404	3 31,130,030	N 100	\$ 318,852,028		\$236,902,662			(\$37,482,970)		3 3,941,587	
2021	1 11 11 00	3 32,343,248	80	\$ 321,902,744		\$229,833,207			(\$38,525,305)		\$ 4,533,935	
2023	5 411 261 024	8 04,100,375	90	3 402,214,978		\$220,904,087			(\$21,864,117)		5 5,656,337	
2023	5 659 108 091	# 100 E02 E44	30	8 487,374,353		\$211,978,818			(\$4,458,380)		\$ 6,986,102	
2024	5 635 704 70B	4 JU2,003,000	\$0	5 650,750,547		\$228,023,862			(\$10,515,113)		\$ 5,583,021	:
2025	3 789 359 510	5 144 060 440	a0	3 /02,658,384		\$232,286,452			(\$35,127,779)		4 820 803	
2026	\$ 948 638 002	\$ 172 336 090	30	5 \$33,419,999		\$277,501,341			(\$52,480,334)		\$ -	
2027	\$ 948,635,002	\$ 175,759,610	00 80	01,120,902,041		3265,265,970			(\$14,155,879)		\$.	
2028	5 851 235 004	\$ 179 752 977	80	#1,124,343,011 E1 130,007,017		\$252,855,491			(\$14,509,776)		\$.	i
2029	\$ 948,636,007	\$ 182 834 115		E 1 431 475 148		\$240,683,666			(\$14,913,268)		s -	
2030	5 948,638,002	\$ 186.477.823		81 116 113 158		8220,802,033			(\$15,244,334)		4 .	
2031	5 948,536,002	\$ 190,184,397		51 108 810 300		8221,795,541			(\$16,525,442)		\$ -	
2032	\$ 951 235,004	5 194,516,781	50	\$1 145 751 706		8219,923,391			(\$16,018,078)		s -	
2033	\$ 948,636,002	\$ 197,852,001	50	51,145,455,003		6206,001,006			{\$16,461,467}		\$	
2034	3 948 638 002	\$ 201,795,033	50	\$1,150,432,035		2104 401 406			(\$16,828,892)		\$ -	
2035	\$ 948,635,002	\$ 205,518,937	50	\$1 154 454 939		\$187,500 170			(517,247,565)		4	
2036	5 651,235,004	\$ 210,497,420	50	\$1,161,732,424		\$107,380,270 \$100 813 906			{\$17,678,754}		\$	
2037	3 \$48,636,002	\$ 214,107,701	\$0	\$1.162 743 703		8174 (000 904			(\$16,170,368)		š •	
2038	\$ 945,636,002	\$ 218,376,811	50	\$1,167.012.812		31/4,006,381			(518,5/3,/41)		\$ -	
2039	\$ 948,636,002	5 222,731,293	\$0	\$1,171,367,264		1100 405 0/1			(819,036,084).		- F	
2040	\$ 951,235.004	\$ 227,795,246	50	\$1,179,030,251		8154 803 878			(319,914,036)		- -	
2041	\$ 948,636,002	5 231,703,238	\$0	\$1,160,339,240		5140 455 418			(320,030,887)			
2042	5 948,636,002	\$ 236,324,219	\$0	\$1,184,960,221		\$144 257 250			(\$20,301,304)		- 5	
2043	\$ 945,635,002	\$ 241,037,609	50	\$1,159,573,511		5139 068 151			(021,019,403)		ia •	
2044	\$ 951,235,004	\$ 248,518,805	50	\$1,197,753,809		\$133 888 349			(521,535,645)		s -	
2045	5 948,638,002	5 250,749,045	\$0	\$1,199,385,047		\$128 726 150			(\$13 630 200)		a -	
2046	S 948,636,002	\$ 255,750,899	\$0	\$1,204,385,801		\$124 265 112			(\$22,030,200)		a .	
2047	5 948,636,002	\$ 250,852,779	\$0	\$1,209,485,781		\$119,014,090			(\$23 775 068)			
2048	5 951,235,004	\$ 266,785,608	\$0	\$1,218,020,612		\$115,372,335			(\$24 437 126)			
2049	5 946,636,002	\$ 271,364,658	50	\$ 1,220,000,659		\$110,941,107			(\$24.979 648)		÷ -	
2050	5 948,636,002	\$ 278,778,777	50	\$1,225,414,779		\$108,520,670			1\$25 504 1071			
2051	5 948,836,002	\$ 282,301,168	\$0	\$ 1,230,837,189		\$101,735,820			1576.244 200			
2052	3 951,235,004	5 268,722,853	\$0	\$1,239,957,668		\$95,952,924			(\$25 974 014)			
2053	> 948,636,002	\$ 293,679,462	\$0	\$1.242,315,464		\$91,510,109			(\$27,572,822)		š i	
ŀ						Upstream Pipeline	Project / Florida Fr	entry Setzine Roe v	Company B Ne	Sauros		E 7 464 010 645
L						Upsineam Pipeline	Project / Florida Ex	NETCY Secure She v	Company P (m)	20123 8 80% 1454	Suine	# 1,909,012,942 # 908,454,999
					and the second						1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1	e 600,471,000

V As the Florida EnergySecure Line Project and the Upstream Pipeline project are not projected to be in service prior to January 2014, casts for this option in 2012 and 2013 represent short-term worksnowed 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) no-electation of firm transportation entitiement rights on FGT (b) acquisition of secondary under the casts and an AREC during these years. It is assumed that these initial needs would be served via a combination of (a) no-electation of firm transportation entitiement rights on FGT (b) acquisition of secondary under the casts and the CCEC and RBEC daring these years is consistent with enter the compression of a secondary Secure of definent as a stand along non-increase pressure of definent data on FGT to required levels. The RBEC compression costs are embedded in overalt Energy Secure during these years is consistent with quantities purchased from Company 8 under the Company 8 along the secure and the secondary values data on FGT to require identical to those with Company 8 secondary capacity required costs are assured to a definent of a company 8 along the secondary capacity required costs are assured to a definent with elected on the secondary capacity required costs are assured to a define and the secondary values dark walkes (same value as release capacity is defined to acquired the secondary capacity required costs are assured to a definent with a defined walkes (same value as release capacity and the secondary capacity required costs are assured to a company 8 under the Company 8 along are assured to a second and capacity required costs are assured to those with Company 8 secondary capacity required costs are assured to the defined walkes (same values a release capacity is defined to a company 8 during these years with this alternative.

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Upstream Pipeline Project - Florida EnergySecure Line Project 1/ Company B Proposal Annual Florida Annual Cast o Demand Lindower Value of otential Seving **Recide Energy** Capacity Release Demand Value of Charges on EnergySecure Fuel Gas Vineline Project Associated with Secure Line of Charges to annuel Cost e Capabity Net Gas Upstream Line Revenue Retained / Commodity Nel Gas **Economic** Company 8 No ransport Cos Activit Activit Company B (\$/Year) **Fuel Relaction** Release Transport soline Projec Requirements Consumed Charges Credits Savings Gas (S/Year) redits (\$/Year Costs (Srrear) (SiYear) (3/Year) (S/Year) (\$/Year) (S/Year) (Sffear) (\$/Yeart (S/Year) Year Column 6 B 9 10 11 12 Sum of Column 1 Column 4 Attachment B Attach ment Column 2+ Attachment IIIA Attachunget IV. Attachment IV Attaolument schment VI A Column 10 + Columns 5 VA, Cel 7 through 9 Column 11 Col 14 VB, Col 7 Column 3 Column 9 Col 13 Col 16 Col 15 Source Attachment Anna Inc. 2012 8,924,700 (58, 198,069 1,725,631 \$1,474,701 52 52 \$ 80,278,207 2013 5 109,254,548 10.111.16 (\$39,087,505) \$61,695,665 (\$151,643,803) 5 828 278 (\$37,787,231) \$ 257,435,487 \$290,851,119 2014 5 267,725,998 \$ 27,496,720 \$ 303,372,987 (\$113,856,572) 50 50 50 \$280,789,254 4 133,138 2015 267,725,998 S 35846988 5 \$ 308,312,585 (\$114,168,508) 3.676.767 2016 5 268,459,494 \$ 39,853,091 \$289,256,843 (8113,856,572) 267,725,996 \$ 311.130.525 \$258,489,524 3.492.079 2017 s \$ 43,404,527 267,725,998 \$ 47,367,421 50 \$ 315.093.419 \$248,394,967 (\$113,856,572) 3,539,604 2018 \$ (\$113,856,572) 257,725,996 \$ 51,138,030 \$0 \$ 315,562,028 \$238,902,952 3 941,567 2019 5 288,459,494 \$ 52,543,249 50 \$ 321,002,744 (\$114,158,508) \$229,833,207 4,533,935 2020 50 \$ 402.214,978 (\$63,213,278 2021 338,114,604 8 64,100,375 \$221,904,087 5,856,337 2022 410,252,924 \$ 77,111,429 \$0 \$ 487,374,353 (\$12,559,984) \$211,978,818 0,988,102 2023 \$58,156,981 \$ 102,583,566 \$0 \$ 660,750,547 \$225,023,962 (\$28,939,025 [\$54,309,505 5,583,921 2024 635,704,708 \$ 117.153,655 50 \$ 752,858,384 \$232,285,452 4,520,503 \$0 & 633,419,959 \$0 \$1,120,952,041 (\$137,480,389) (\$38,175,781) 2025 789,359,510 \$ 144,060,449 \$277,501,541 2028 2027 948,636,002 \$ 172,326,039 \$265,265,970 948,636,002 \$ 175,759,610 50 81 124 395 611 \$252,655,491 (\$38,173,741) 951,235,004 5 179,752,972 \$0 \$1,130,987,977 \$240,583,655 (\$35,272,888) 2028 2029 948,638,002 \$ 182,834,115 \$0 \$1,151,470,118 \$229,952,839 (\$35,173,781) 2030 948,538,002 \$ 185,477,823 \$0 \$1,135,113,825 \$221,798,541 (\$36,173,781) (\$38,173,781) (\$38,272,888) 2031 945,636,002 \$ 190,194,397 50 \$1,138,830,299 \$214,923,391 2032 851,235,004 \$ 194,516,761 50 \$1,145,751,765 \$206,081,606 (\$38,173,781) 2033 948.635,002 \$ 197,852.001 30 \$1,145,458,003 50 \$1,150,432,035 8201,221,095 \$194,402,068 945,636,002 \$ 201,796,033 946,636,002 \$ 205,618,937 (\$36,173,781) 2034 80 \$1,154,454,839 2035 \$187 590 270 (\$36,173,781) (\$35,272,888) 2036 951 235 004 \$ 210,497,420 50 \$1,151,732,424 \$180,813,808 848,836,002 \$ 214,107,701 50 \$1,182,743,703 (\$36,173,781) 2037 \$174,002,391 2038 945,636,002 \$ 218,378,611 80 \$1 167 012 812 \$167,305,670 (\$36,173,781) 2039 945,636,002 5 222,731,293 50 \$1,171.357,294 5160,968,941 (\$38,173,781) (\$35 272.068 2040 851,235,004 \$ 227,795,248 50 \$1,179,030,251 \$154,893,975 (\$35,173,781) \$148,455,418 2041 948,636,002 3 231,703,238 50 \$1,100,339,240 (\$38,173,781) 2042 2045 2044 2045 948 636 002 5 238 324 219 30 \$1,184,980,221 50 \$1 189 675 611 \$139,088,151 (\$35,173,781) 5 241,037,609 948 535 002 \$133,688,349 951,235,004 246.516 605 50 \$1,197 753 000 (\$36,272,886) (\$36,173,781) 80 \$1,199,385,047 \$126,728,150 948,636,002 5 250,749,045 (\$35,173,781) 2045 948,636,002 255,750,899 50 \$1 204 206 901 \$124,255,112 \$119,814,090 \$115,372,335 \$110,941,107 (\$35,173,781) 2047 848,636,002 260,852,779 \$0 \$1,209,488,781 2048 2048 2050 \$0 \$1,218,020,612 (\$36,172,685) (\$36,173,781) 951,235,004 265,765,606 \$0 \$1 220,000,659 948,636,002 \$ 271.384.658 \$ 276.778.777 \$106,520,670 (\$36,173,781) 948,636,002 \$0 \$1,225,414,779 2051 \$101,735,820 (\$36,173,761) 948,636,002 \$ 282,301,168 50 \$1 230 037 180 \$96,952,924 2052 951,235,004 \$ 258,722,853 90 \$1,239,957,858 (\$35,272,666 (\$38,173,781) 2063 946,636,002 5 293,679,462 \$1,242,315,464 \$91,510,109 Upsineem Pipeline Project / Plantae Energy Secure line vs. Company B Net Sevings Upsineem Pipeline Project / Flantae Energy Secure line vs. Company B (@2012) 8.89% MPV Savings \$ 6,543,763,642 756,782,464

1/ As the Floride 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 worksround costs required to shable testing and initial usage of the CCEC and REEC auting these years. It is essumed that these initial energy meaks would be served via a combination of (a) n=vitication of film ramspontation entitiement rights on FGT (b) consistent and required to shable market capacity and (c) the installation of most compression at the CCEC and REEC as an REEC as an REEC as an REE as a required to increase pressure of belowing these from the section of the version of the version of the version of the version of the transpontation entitiement rights on FGT (b) constrained from the section of the version of the VERC compression costs are advected by Sector Une project settimate and the CCEC on-site acceptession cost is added as a mind alone incremental reverse requirement (as estimated by FPL). In addition, as a constant with quantities prohested in the company B structured to the Cempany B structured to the Cempany B structured to the Cempany B structured as in the CCEC on-site accepted by Company B structured via Company B structured as a transfer values (same value as networks e assumption, it is assumed that secondary required during these years is consistent with quantities prohested in the Cempany B structured in the second secondary assumption, it is assumed to the Cempany B structured via Company B structured as in the second secondary assumption, it is assumed to a site of the Cempany B structured via Company B structured as the secondary assumption as a constant with quantities prohested in the company B structured via Company B structured with the structure secondary assumption, it is assumed to be assumed as the secondary assumption as a constant with quantities (same value as networks excepted via Company B structured via Company B structured via Company B structure secondary and the struc

Summary Comparative Cost Analysis Case B - Excess Capacity Valued at FGT Phase Vill Maximum Tariff Rate

Analysis 2 Updated Gas Cost Savings . Exhibit TCS-8, Page 4 of 2[,] Docket No. 090172-EI

Company 8 Proposal Upstream Pipeline Project - Florida EnergySecure Line Project 1/ Annuel Florida stential Savings Demand Annual Cost of Upstrea Value of Florida Energy Demand Value of Charges on Upstream Associated will EnergySecure Fuel Gas pelloe Proje Capacity Secure Line vs. Charges to innual Cost of Capacity Net Gas Line Revenue Retained i Commodity Release Net Gas Economia Company 9 Nel Company B Fuel Retentio Reisace Transport ficeliste Projec Savings HTT: CONSISTER Charges Cravitie Insport Cos Epstch Activi Yea (SiYear) Gas (\$/Year) Credits (S/Year Costs (\$/Year (\$Year) (SrYeer) (S/Year) (S/Year) [S/Year] (S/Year) (S/Yeari (SiYear) Column 4 2 з -5 10 11 12 Column 1 Sum of Column 3 Attackment i Attachment Column 2+ Attachment IBA. Attachment IV. Attachment IV Attachment Columns 5 (Column 10 -VA, Col 9 Source Attachment (Col 14 VB, Col 9 Column 3 Attachagent IS Galumo 14 Col 16 Col 13 Ørrough 9 Col 18 Colume 11] 2012 9.924,700 9,924,700 \$0 \$0 \$0 1 2013 109.254.548 10,111,184 \$ 119,365,712 \$4,334,755 8888888 2014 267,725,998 27,495,720 \$ 295,222,718 \$290,851,119 15,029,194 2015 267.725.998 35,646,988 50 5 303,372,987 \$280,769,254 11,328,875 2018 288,459,494 39,853,091 50 50 \$ 308,312,585 \$259,256,843 11,178,973 2017 267,725,996 41 404 827 \$ 311,130,625 \$258,489,624 11,328,223 \$0 \$ 315,083,419 \$0 \$ 318,862,028 \$0 \$ 321,002,744 \$0 \$ 402,214,978 2018 267,725,996 47,387,421 \$248,394,987 11,856,661 2019 267,725,998 51,136,030 \$236,902,662 12,902,034 2020 268,459,494 52,543,249 \$229,839,207 13,908,389 2021 338,114,604 64,100,375 \$220,904,087 11,104,481 30 \$ 487,374,353 50 \$ 660,750,547 2022 410,262,924 77,111,429 \$ 487,374,353 3211.978.618 8,041,577 2023 558, 166,981 102,583,566 \$725 023 662 7,072,985 50 8 660,750,547 50 8 762,858,364 50 8 933,419,959 50 \$1,120,962,041 50 \$1,124,395,811 30 \$1,135,087,977 50 \$1,135,470,118 50 \$1,135,113,825 2024 635 704 705 5 117 163 656 \$232,285,452 8,562,322 2025 788,359,510 S 144.0ED 449 \$277,501,341 2025 948,636,002 \$ 172,326,039 \$285,265,970 2027 948,838,002 5 175 759 610 \$252,856,491 \$ 2028 851,235,004 \$ 179,752 972 \$240,583,565 \$ 2029 948,638,002 \$ 182,834,115 \$228,952,833 3 2030 948,638,002 \$ 186,477,823 \$221.798,541 2031 948,635,002 \$ 180,194,397 30 \$1,138,830,399 50 \$1,145,751,765 5214 923 391 2032 951,235,004 \$ 194,518,781 5206.081.605 2033 848,636,002 197,852,001 50 \$1,146,458,003 \$201 221 093 \$ \$ 2034 948,638,002 \$ 201,796,033 \$0 \$1,150,432,035 \$194,402,098 2035 948,636,002 5 206,818,937 \$0 \$1,154,454,939 \$187,590,270 5 30 51,151,732,424 30 51,162,743,703 30 51,167,012,612 30 51,171,367,294 2038 2037 951,235,004 \$ 210,497,420 \$190,813,805 948,635,002 \$ 214,107,701 \$174,002,391 2038 948,638,002 \$ 218,378,811 \$187,308,670 \$ 2039 945,638,002 \$ 222,751,293 \$150,868,941 2040 951,235,004 \$ 227,795,246 \$0 \$1,179,030,251 \$ \$ 5 5 5 5 2041 948,836,002 \$ 231,703,238 \$0 \$1,160,358,240 \$149,455,418 2042 948,656,002 \$ 238.324,219 \$0 \$1,184,980,221 \$144,257,250 2043 \$0 \$1,189,673,611 \$0 \$1,197,753,609 G48 636 002 5 241,037,609 \$138,088,151 5 5 2044 951,235,004 \$ 246,518,805 \$133,888,349 2045 945,536,002 250,749,045 \$0 \$1,199,385,047 \$0 \$1,204,385,901 \$128,726,150 2046 948.636.002 \$ 255,750,899 \$124,266,112 2047 948,535,002 \$ 260,652,779 \$0 \$1,209,468,781 \$119,814,090 \$115,372,335 2048 951,235,004 \$ 268,785,608 50 \$1,218,020,812 ŝ 2048 948,636,002 271,364,656 50 \$1,220,000,859 \$110 941 107 2050 948,636,002 \$ 276,778,777 50 \$1,225,414,779 \$106,520,670 3 5 2051 948.636.002 282,301,168 \$0 \$1,230,937,189 \$101,735,820 2052 951 235 D04 5 288,722,653 \$0 \$1,234,857,858 \$95,952,924 2053 946,635,002 \$ 293,678,462 50 \$1,242,315,464 \$91,510,109 Upstream Pipeline Project / Florida Energy Secura line vs. Company B Nat Savings Upstream Pipeline Project / Florida Energy Secura line vs. Company B (@2012) 8.86% NPV Savings \$ 6 677 344 354

\$ 122,719,777

1/ As the Floride EnergySecure Line Project and the Upstream 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 lesting and initial usage of the CCEC and RBEC during taxes years. It is assumed that these halfs needs would be served via a combination of (a) re-allocation of firm transportation entitlement rights on FGT (b) application of secondary market capacity and (c) the installation of onalis compression at the CGEC and RBEC as required to increase pressure of delivered gas on FGT to required levels. The RBEC compression costs are embedded in overalt Brargy Sectors Une project estimate and the CCEC on-site compression cost is added as a stand alone incremental neverne requirement (as estimated by FPL). In addition, as a conservative assumption, it is assumed that secondary capacity required during these years is constainent with quantities purchased from Company B under the Company B alternative and is purchased at mantet values (same value as release capacity is presumed sold). Finally, transportation field 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 atternetive.

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Summary Comparative Cost Analysis Case C - Excess Capacity Given No Value in Marketplace

)172-EI	ost Savings Analys	Page 5 of 24
Docket No. 091	Updated Gas C	Exhibit TCS-8

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Year	1	2012		2013		2014		2015		2016		2017		2018
Company B Proposed Rate - Escalated at 2.5% per year 1/2/	\$	1.627	\$	1.627	\$	1, 64 6	\$	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)	<u> </u>		Ļ			400,000	<u> </u>	400,000		400,000	<u> </u>	400,000	Ļ	400,000
							[1	
Company B Base Proposal	1	50.000		400 000		400.000		400.000		400.000		400 000		400 000
Company B Res Fee (\$/MMRtu)	5	1 627	\$	1 627	\$	1.627	s	1.627	s	1.627	\$	1.627	s	1.627
MDO on Transco 85 to Company B (\$/MMBtu) (grossed up for Company B Fuel)	1	-	*	413.479	•	413.479	1	413.479	1	413.479	-	413,479	1	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											l.			
MDQ (MMBtu/day)						-		-		•	e	-	e	-
MDO on Transco 85 to Company B (\$/MMBtu) (grossed up for Company B Eusl)					*		۳.				Ψ	-		
Transco 85 to Company B Reservation Charge (\$/MMBtu)					s	-	5	-	\$	-	\$	-	\$	-
					L						<u> </u>			
Capacity Addition 2														
MDQ (MMBtu/day)			1			-		-	١.	-		-		-
Reservation Charge (\$/MMBtu)					\$	-	\$	-	\$	-	\$	-	\$	-
MDQ on Transco 85 to Company B (\$/MMBtu) (grossed up for Company B Fuel)			1			-	e	-	e	-	e	-	æ	-
Transco 65 to Company B Reservation Charge (\$MMBtd)	· ·····				•		 •		1			-	*	
Capacity Addition 3			i i						ŀ					
MDQ (MMBtu/day)	1		ł		1	-		-		-		-		-
Reservation Charge (\$/MMBtu)			ļ.		\$	-	\$	-	\$	-	\$	-	\$	-
MDQ on Transco 85 to Company B (\$/MMBtu) (grossed up for Company B Fuel)	1					-	1.	-		-		-		-
Transco 85 to Company B Reservation Charge (\$/MMBtu)			<u> </u>		5_	•	\$	-	\$	-	\$	-	\$	-
Capacity Addition 4			ł											
MDQ (MMBtu/day)								-		-		-		-
Reservation Charge (\$/MMBtu)	1				\$	-	\$	-	\$	-	\$	-	\$	-
MDQ on Transco 85 to Company B (\$/MMBtu) (grossed up for Company B Fuel)						-	1	-		-		-		-
Transco 85 to Company B Reservation Charge (\$/MMBtu)			ļ		\$	-	\$	÷	 \$		\$	-	\$	-
Capacity Addition 5														
MDQ (MMBh/day)						-		- 1		-		-		-
Reservation Charge (\$/MMBtu)					\$	-	\$	-	\$	-	\$	-	\$	-
MDQ on Transco 85 to Company B (\$/MMBtu) (grossed up for Company B Fuel)						-		-	1	-		-		-
Transco 85 to Company B Reservation Charge (\$/MMBtu)					\$		\$	-	\$	-	\$	-	\$	<u> </u>
Conneity Addition 6									1					
								_		-		-		-
Reservation Charge (\$/MMBtu)					\$		s	_	s		\$	-	\$	- "
MDQ on Transco 85 to Company B (\$/MMBtu) (grossed up for Company B Fuel)					Ť	-		-		-		-		-
Transco 85 to Company B Reservation Charge (\$/MMBtu)					\$		<u>i s</u>	-	\$	-	\$	-	\$	-
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

Attachment I

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 steei price tracker adjustiment 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.

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ţ			2010	T	2020	<u>1</u>	2024	<u> </u>	1012	-	2022	1	2024		20.25
2	Company & Proposed Rate - Escalated at 2.5% per year 1/2/	e	2019	١.	2020		2021	e	2022		2023	e	2024	l e	2025
5	Rate for Potential Pineline from Transco 85 to Company B - Escalated at 2.5% per year 3/	l ç	0.228		0.334		0.940	¢	0.246		a 2.000 t 0.252	5	0.258	ŝ	0.265
5	FPL Demand (MMBtu/day)	*	400.000	1*	400 000	1	487 500	۳ ا	575 000		750.000		837 500	•	1 012 500
ц З		┢	400,000	┢	400,000	┿	401,000		010,000		730,300	-		-	1,012,000
-	Company & Base Proposal					1									
p	Company B MDQ (MMBtu/day)		400.000		400.000		400.000		400 000		400.000	ĺ	400.000		400.000
	Company B Res. Fee (\$/MMBtu)	\$	1.627	s	1.627	1 \$	1.627	\$	1.627	\$	1.627	\$	1.627	\$	1.627
)	MDQ on Transco 85 to Company B (\$/MMBtu) (grossed up for Company B Fuel)	ľ	413,479	ľ	413.479	1	413.479	17	413.479	-	413,479	Ĩ	413,479	ľ	413,479
1	Transco 85 to Company B Reservation Charge (\$/MMBtu)	15	0,200	\$	0.200	\$	0,200	ls	0.200	s	0.200	s	0,200	\$	0,200
5		t		F		Ť						Ē			
	Capacity Addition 1														
ŝ	MDQ (MMBtu/day)		-		-		87,500		87,500		87,500		87,500		87,500
	Reservation Charge (\$/MMBtu)	\$	-	\$. -	\$	1.956	\$	1. 9 56	\$	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			F											
	MDQ (MMBtu/day)		-	İ.	-	۱.	-		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)	12	-	13		15		\$	0.246	\$	0.246	*	0,246	\$	0.246
	Canacity Addition 3														
	MDO (MMBtu/day)		-				_	ł			175.000		175.000		175.000
	Reservation Charge (\$/MMBtu)	\$		ß		s	_	\$	-	s	2 055	s	2 055	\$	2 055
	MDQ on Transco 85 to Company B (\$/MMBtu) (prossed up for Company B Fuel)	*	_	*	_	ľ	-	•	-	Ť	180.897	ľ	180.897	*	180,897
	Transco 85 to Company B Reservation Charge (\$/MMBtu)	\$	-	\$	-	s	-	\$	· _	\$	0.252	\$	0.252	\$	D.252
				F		Ť									
	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)	Ε.	-	[.	-	1	-		-		-		90,449		90,449
	Transco 85 to Company B Reservation Charge (\$/MMBtu)	\$	-	\$	-	\$	-	\$	-	\$	-	\$	0.258	\$	0.258
	Canasity Addition E					1									
															176 000
	Receivation Charge (\$MMRtu)		-		-		-	¢	-	¢	•	¢	-	e	2 150
	MDD on Transco 85 to Company B (\$8/MBtu) (grossed up for Company B Fuel)	♥	-	17	-	1 *	-	Ψ	-	•	-	\$	-	φ	190 907
	Transco 85 to Company B Reservation Chame (\$/MMRtu)	\$		¢		\$		s	_	¢	_	\$		\$	0 265
		ť				 [●]				Ť				•	
	Capacity Addition 6														
	MDQ (MMBtu/day)		-		-		-		-		-		-		-
	Reservation Charge (\$/MMBtu)	\$	-	\$	-	\$	-	\$	-	\$	-	\$		\$	-
	MDQ on Transco 85 to Company B (\$/MMBtu) (grossed up for Company B Fuel)		-		-		-		-		-		-		-
ļ	Transco 85 to Company B Reservation Charge (\$/MMBtu)	\$	<u> </u>	\$	-	\$		\$	- ,	\$	-	\$	-	\$	-
	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

Attachment I

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.

•															
1	Year		2026		2027		2028		2029	1	2030		2031	1	2032
1	Company 8 Proposed Rate - Escalated at 2.5% per year 1/2/	ĺs.	2 213	\$	2 260	6	2 325	l c	2 383	ĺe	2 4 4 3	c l	2 504	t	2 567
	Rate for Potential Pipeline from Transco 85 to Company B - Escalated at 2.5% per year 2/	l e	0.271	ě	0.979	1.	0.995	1.	0.000		0.000	L.	0.307		0.345
ć	FPI Demand (MMR/u/dav)	۳ ا	4 403 600	*	0.270	۳ ا	0.200	₽	0.252	♥	0.255		4 407 500	4	0.515
ſ.		_	1,187,500		1,187,500	<u> </u>	1,187,500		1,187,500		1,187,500	_	1,187,500		1,187,500
•															
5	Company B Base Proposal					1									
<u>،</u>	Company B MDQ (MMBtu/day)		400.000	1	400 000	1	400 000		400.000		400.000		400 000		400 000
5	Company B Res. Fee (\$/MMBtu)	e	1 627	e	1 607		1 627		1 607	l e	1 6 3 7	•	1 6 2 7	e	1 607
ί.	MDO on Terreso P5 to Company R (\$(MMRts)) (grouped up for Company R Fuel)	 *	440.470	•	1.027	1 *	1.027	•	1,027	P	1,027	1.	1.027	۳	1.027
	Transce of transce of the company B (shimiled) (grossed up for Company B Fuel)		413,479		413,479	Ι.	413,479		413,479	Ι.	413,479	F.	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
		1				1		[
	Capacity Addition 1					1								1	
1	MDQ (MMBtu/day)	1	87.500		87 500	1	87 500		87 500		87,500		87 500		87 500
ł	Reservation Charge (\$/MMBtu)	8	1 956	e	1 956	l e	1 956	¢	1 956	e	1 956	¢	1 956	e	1 956
	MDO on Transco 85 to Company B (\$64MBtu) (grossed up for Company B Eucl)	1*	00.440	*	00.440	۳.	00.440	۳.	00.440	۳.	00.440	۳.	00.440	Ŷ	00.440
	Transon 95 in Company D (animutal) (allossed up to Company B Fuel)		90,449		90,449	1.	90,449		90,449		90,449		90,449		90,449
	Transco 65 to Company B Reservation Charge (S/MM880)	\$	0.240	\$	0.240	15	0.240	\$	0.240	L <u>\$</u>	0.240	5	0.240	\$	0.240
		1				1									
ł	Capacity Addition 2	1		f											
ł	MDQ (MMBtu/day)	1	87,500		87.500		87,500		87,500		87.500		87.500		87.500
	Reservation Charge (\$/MMBtu)	5	2 005	\$	2 005		2 005	•	2,005	e.	2 005	\$	2 005	2	2 005
	MDQ on Transco 85 to Company B (\$/MRtu) (grossed up for Company B Eucl)	۳.	00.440	•	00.440	۳.	00.440	*	00.440	♥	00.440	•	00.440	Ť	00.440
	Transco 85 to Company B Decongriga Champing (Galilath)		50,445		90,449		90,449		90,449		90,449		90,449		90,449
	Trainsco os to Company B Reservation Charge (SrMMBdd)		0,246	\$	0.246	\$	0.246	\$	0.246	\$	0.246	\$	0.246	\$	0.246
													ł		
	Capacity Addition 3												1	1	
	MDQ (MMBtu/day)		175,000		175,000		175,000		175,000		175,000		175,000	1	175,000
	Reservation Charge (\$/MMBtu)	s	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 Euel)	1	180 807	•	180 807	1.	180 897	•	190 897	•	180 897	•	190 807	Ť	180 907
ł	Transco 85 to Company B Reservation Charge (\$/MMPtu)	e	0.252	e	00,007	e	0.252	æ	0.251	•	00,001		0.252		0.057
	Hander of the Service and Service (animited)		0.202	9	0.232	1.0	0.202	\$	0.232	.	0.232		0.252	₽	0.232
	Capacity Auguron 4														
	MDQ (MMBtu/day)		87,500		87,500	I I	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
1	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
ľ	Transco 85 to Company B Reservation Charge (\$/MMBtu)	s	0.258	\$	0 258	\$	0 258	\$	0 258	\$	D 258	\$	0.258	s	0 258
l		+-	0.200	•	0.200	<u>†</u> *•		<u> </u>	. 0,200	¥	0.400	Ψ	0.200	Ť	0.200
	Capacity Addition 6	1													
	MDO (MMRtuday)				175 000		175 000								
ł		.	175,000		175,000	1	175,000		175,000		175,000		175,000		175,000
1	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
Į										,				÷	
Ĭ.	Capacity Addition 6	1													
ľ	MDQ (MMBtu/day)		175 000		175 000		175 000		175 000		175 000		175 000		175 000
	Deconsting Charge (\$48/Dt.)		1/5,000		1/5,000		175,000		1/5,000		1/5,000		175,000	-	1/5,000
		\$	2.213	\$	2,213	5	2,213	\$	2.213	\$	2.213	5	2.213	\$	2,213
ł	WDQ on Transco ab to Company B (\$/MMBtu) (grossed up for Company B Fuel)		180,897		180,897	l.	180,897		180,897		180,897		180,897		180,897
L	Transco 85 to Company B Reservation Charge (\$/MMBtu)	\$	0.271	\$	0.271	\$	0.271	\$	0.271	\$	0.271	\$	0.271	\$	0.271
ľ		1												-	
	Annual Cost of Reservation Charges	15	948,636,002	\$	948,636,002	5	951,235,004	\$	948.636.002	\$	948,636,002	\$	948,635 002	\$	951 235 004
100						. 7		T		-		•		7	

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.

. 1															
5	Year	1	2033		2034		2035		2036	Γ	2037		2038		2039
s	Company B Proposed Rate - Escalated at 2.5% per year 1/2/	5	2 631	1.8	2 697	5	2 764	s	2,833	\$	2.904	\$	2.977	\$	3.051
,	Rate for Potential Pineline from Transco 85 to Company B - Escalated at 2.5% per year 3/	1.	0 322	l ē	0.330	١.	0 339	Š.	0.347	ŝ	0.356	s	0.365	\$	0.374
٥	FPL Demand (MMBIu/day)	1	1 197 500	♥	4 197 500	۳.	1 197 500	۳.	1 187 500	•	1 197 500	1 T .	1 187 500	•	1 187 500
		-	1,107,000		1,107,500		1,101,000	+	1,101,000		1,101,000	-	1,107,000		1,101,000
													l		
'	Company B Base Proposal											[
	Company B MDQ (MMBtu/day)		400,000		400,000		400,000		400,000		400,000		400,000		400,000
1	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)	1	413,479		413,479		413,479		413,479		413,479	i .	413,479		413,479
	Transco 85 to Company B Reservation Charge (\$/MMBtu)	5	0.200	15	0.200	5	0.200	\$	0,200	5	0.200	\$	0,200	\$	0.200
		+ ·		1		<u> </u>		†							
	Capacity Addition 1														
	MDO (MAMBHU/day)		97 500		97 600		87 500		97 500		87 500	ľ	87 500		87 500
	Page (film blad day)		67,500	١.	000,10		67,300		01,000		1,000		1 050		1 066
		1.5	1.900	•	1.950	1.2	1.900] @	1.936	3	1,950	Ф	1.900	*	1.550
	MDQ on Transco 85 to Company B (\$/MMBtu) (grossed up for Company B Fuel)		90,449	ŧ.	90,449	Ι.	90,449		90,449	١.	90,449		90,449		90,449
	I ransco 85 to Company B Reservation Charge (\$/MMBtu)	\$	0.240	\$	0.240	\$	0.240	15	0.240	\$	0.240	\$	0.240	\$	0.240
														ļ	
	Capacity Addition 2														
	MDQ (MMBtu/day)	1	87,500		87,500		87,500		87,500		87,500		87,500		87,500
	Reservation Charge (\$/MMBtu)	Is	2 005	\$	2.005	\$	2.005	\$	2.005	s	2.005	\$	2,005	\$	2.005
	MDQ on Transco 85 to Company B (\$/MMBtu) (grossed up for Company B Fuel)	1	90 449	•	90 449	1	90 449	1	90 449	1	90 449		90 449		90,449
- 8	Transco 85 to Company B Despration Charge (\$MMRhi)	l e	0,440	l e	0.246	e le	0 246	4	0 246	¢	0.246	\$	0 246	¢	0 246
	Hanse of to company Diffeschadon chaige (annuald)	+*	0.240	1.	0.240	۴	0.240	14	0.240	ا پ	0.470	Ŷ	0.240	¥	0.2.10
	Compate Addition 3														
										1			175.005		175 000
ł	MDQ (MMBtu/day)		175,000		175,000		175,000	Ι.	175,000		175,000		175,000		175,000
ł	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	1	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
l		-								T					
	Capacity Addition 4												ļ		
1	MDQ (MMBtu/day)		87.500	1	87.500		87.500		87,500		87.500		87,500		87.500
	Reservation Charge (\$/MMBtu)	5	2 107	15	2 107	\$	2 107	\$	2,107	\$	2,107	\$	2,107	\$	2,107
	MDO on Transco 85 to Company B (\$MMBtu) (grossed up for Company B Euch	۳.	00 440	۳.	00.440	۳.	00 440	۳.	00.449	۳.	90.449	•	90.449	•	90 449
1	Transce of 85 to Company B Company of Community (grossed up to Company of Lee)		01440		0.259		0,445	l e	0,759	e	0.259	e	0.258	e	0.259
	Transee bs to company a reservation onarge (winitibitia)	1.0	0.200	1	0.230	♥	0.200	≁	0.200	-	0.200	*	0.200	*	0.200
ł	Connector Addition 5	1											ļ		
ŀ	Appender Verbauer						175 000		-75 000		475 000		175 000		175 000
	MDQ (MMBtu/day)		175,000		175,000	Ι.	175,000		175,000		175,000		175,000		1/5,000
1	Reservation Charge (\$/MMBtu)	\$	2.159	\$	2.159	\$	2.159	\$	2.159	\$	2.159	5	2.159	\$	2.159
1	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
l	Transco 85 to Company B Reservation Charge (\$/MMBtu)	\$	0.265	\$	0.265	\$	0.265	\$	0,265	\$	0.265	\$	0.265	\$	0.265
						T T									
ŀ	Capacity Addition 6					1									
ſ	MDQ (MM8tu/day)		175,000		175,000		175,000		175,000		175,000		175,000		175,000
1	Reservation Charge (\$/MMBtu)	s	2,213	\$	2,213	\$	2,213	\$	2,213	\$	2,213	\$	2,213	\$	2,213
	MDO on Transco 85 to Company B (\$/MMBtu) (prossed up for Company B Fuel)	1 T	180 897	Ť	180 897	L.	180 897	Ľ	180 897	1	180,897		180,897		180,897
	Transco 85 to Company B Reservation Charge (\$/MMRtu)		8 271	\$	0 271	\$	0 271		0 271	\$	0 271	\$	0 271	\$	0 271
╟	The second s	+*	0,211	÷	0.271	÷	0.271		0.271		0,211	Ψ	0.211	Ψ	0.271
1	Annual Cost of Reservation Charges	15	948,636,002	5	948,636,002	15	948,635,002	15	951,235,004	5	948,636,002	5	948,635,002	\$	548,636,002

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.

Vear Decremary Brower Rate - Excellated at 2.5% per year 1/2/ EPU Commun Breaker Rate - Excellated at 2.5% per year 3/2 2044 2045 2044						_									
Company B Proposed Rate - Escalable at 2.5% per year 1/2/ Rate for Potentiar Playment MMRbulk \$ 3.328 \$ 3.282 \$ 3.288	Year		2040		2041	1	2042		2043	[2044		2045		2046
Tetle for Polemital Products for Company B - Escalated at 2.5% per year 3/ \$ 0.333 \$ 0.433 \$ 0.433 \$ 0.433 \$ 0.444 \$ 0.443 \$	Company B Pronosed Rate - Escalated at 2.5% per year 1/2/	•	3 1 2 7	¢	3 205	\$	3 286	5	3 368	8	3 452	S	3 538	\$	3.627
Deputy Deputy S 1.157.500 1.117.500 <td>Bate for Detailing Discling from Transport of the Operation of the Soft and the Sof</td> <td>, č</td> <td>0.127</td> <td></td> <td>0.200</td> <td>1.</td> <td>0.400</td> <td>1.</td> <td>0.412</td> <td>1.</td> <td>0.402</td> <td>l è</td> <td>0.434</td> <td>č</td> <td>0.444</td>	Bate for Detailing Discling from Transport of the Operation of the Soft and the Sof	, č	0.127		0.200	1.	0.400	1.	0.412	1.	0.402	l è	0.434	č	0.444
rr_C Company B activity 1.187.200 1	EDI Demond (Millor) (An International Transco 65 to Company B - Escalated at 2.5% per year 3/	\$	0.383	•	0.393	•	0.403) Þ	0.413	»	0.423	•	4 4 67 5 66		4 407 500
Company B Base Property Company B MDQ (MMBuday) 400,000<	PL Demand (MMBtu/day)		1,187,500	<u> </u>	1,187,500	L	1,187,500		1,187,500		1,187,500	L	1,187,500		1,187,500
Company B Base Proposal Company B Rox, Fee (SAMBLu) Company B R				Т		Г		ľ				<u> </u>			
Company B ADQ (MMBulgy) 400,000	Company B Base Proposal														
Collegary B McU (MMB)(2000) Collegary B McU (MMB)(2000) <t< td=""><td></td><td></td><td>400.000</td><td></td><td>100 000</td><td>l</td><td>400.000</td><td></td><td>400.000</td><td></td><td>400 000</td><td>ļ.</td><td>400.000</td><td></td><td>400.000</td></t<>			400.000		100 000	l	400.000		400.000		400 000	ļ.	400.000		400.000
Company Res. Fee (SMMBib) \$ 1,627 \$ 1,6	Company B MDQ (MMB(U/day)		400,000	Ι.	400,000	L .	400,000	Ι.	400,000		400,000	I.	400,000		400,000
MDC on Transco 85 to Company B (\$MMBtu) (grossed up for Company B Fuel) 413,479	Company B Res. Fee (\$/MMBtu)	\$	1.627	\$	1.627	\$	1.627	\$	1,627	\$	1.627	\$	1,627	\$	1,627
Transco 85 to Company B Reservation Charge (SMMBtu) \$ 0.200 \$ 0.2	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
Cancel Cold Bong and Distance (Similar) Cold Biological Distance (Similar)	Transco 85 to Company B Reservation Charge (\$/MMBtu)	5	0 200	e .	0.200	5	0,200	5	0.200	8	0 200	\$	0.200	\$	0.200
Capacity Addition 1 (NOC (MMBRU) Reservation Charge (SMMBRU) (grossed up for Company B Fuel) S 1956 1956 1956 1956 1956 1956 1956 1956	Transie as to company of reservation owarge (ontimotio)	÷	0,200	l.	0.200	+		+	0,200	⊢ •	0.200	Ť		. *	
Capacity Addition 1 MOQ (MMBBub) (grossed up for Company B Leih) S 7,500															
IMDC (MMBLu/day) ST.500 <	Capacity Addition 1					1									
Reservation Charge (SMMBtu) MOC on Transco 85 to Company B (SMMBtu) (grossed up for Company B Fuel) \$ 90,449	MDQ (MMBtu/day)		87,500		87,500	1	87,500		87,500		87,500		87,500		87,500
NDC on Transce 85 in Company B (\$MMBtu) (grossed up for Company B Fuel) \$0,240 \$0,246 \$0,246 \$0,246 \$0,246 \$0,246 \$0,246 \$0,246 \$0,246 \$0,246 \$0,246 \$0,246 \$0,246 \$0,246 \$0,246 \$0,246 \$0,246 \$0,246 \$0,449 \$0,449 \$0,449 \$0,449 \$0,449 \$0,449 \$0,446 \$0,446 \$0,446 \$0,446 \$0,446 \$0,446 \$0,446 \$0,446 \$0,446 \$0,446 \$0,446 \$0,446 \$0,446 \$0,446	Reservation Charge (S/MMBtu)	\$	1.956	\$	1.956	5	1.956	\$	1.956	5	1.956	5	1.956	\$	1.956
Inclusion of the last of company G Reservation Charge (\$MMBtu) S 0.240	MDO on Transco 85 to Company B (\$/MMBtu) (grospod up for Company B Fuel)		00 440	T .	00 440	1	00 440	<u>۱</u>	014 00	*	90 449	· ·	00 449		90 449
Transco 85 to Company B reservation Charge (\$MMBtu) \$ 0.240 \$ 0.2	The of the first of the company is (an information) (grossed up for company is Puery		50,445		50,445		30,443		30,443		00,440		00,-+0		0.040
Capacity Addition 2 MDQ (MMBu/day) Reservation Charge (SMMBb) (grossed up for Company B Fuel) Transco 85 to Company B Reservation Charge (SMMBb) (grossed up for Company B Fuel) 87,500 S 2,005 87,500 S 2,026 87,500 S 2,025 87,500 S 2,025 87,500 S 2,025 87,500 S 2,025 87,500 S 2,025 87,500 S 2,055 87,500 S 2,0255 87,500 S 2,055 87,5	Transco 85 to Company B Reservation Charge (\$/MMBtu)	5	0.240	\$	0.240	<u> </u>	0.240	\$	0.240	13	0.240	3	0.240	3	0.240
Capacity Addition 2 MDC (MMBRu/day) 87,500 87															
INDC (MMBBu/day) B7.500 87.500 <	Capacity Addition 2														
Reservation Charge (\$MMBlu) \$ 2,005 \$ 0,246 \$ 0,255 \$ 2,055 \$ 2,055 \$ 2,055 \$ 2,055 \$ 0	MDQ (MMBtu(day)		87 500		87 500	1	87 500		87 500		87.500		87,500		87.500
Reservation Charge (SMMBtu) \$ 2,000	Descrition Charge (CAMDA)		01,500		0,000		2,000		2,005		1 005		2 005	e	2 005
MDC on Transco 85 to Company B (\$MMBtu) (grossed up for Company B Fuel) 90,449	Reservation Charge (\$/MMBtu)	2	2.005	\$	2.005	12	2.005	•	2.005	»	2.005)	2.005	Φ	2.005
Transco 85 to Company B Reservation Charge (\$/MMBtu) \$ 0.246 \$ 0.256 \$ 0.256 \$	MDQ on Transco 85 to Company B (\$/MMBtu) (grossed up for Company B Fuel)	1	90,449		90,449		90,449		90,449		90,449		90,449		90,449
Capacity Addition 3 MDQ (MMBtu/day) 175,000	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) r				-										T.	
Internation Charge (\$MMBtu/day) 175,000 180,897 180,897 180,897 180,897 180,897 180,897 180,897 2,017 \$ 2,107 \$ 2,107 \$ 2,107 \$ 2,107 \$ 2,107 \$ 2,107 \$ 2,107 \$	Canacity Addition 3			1											
MDQ (MMBRU/Bay) 175,000 180,897 180,997 2.107 \$ 2.107<			475 000		475 000	i –	475 000		475 000		475.000		175 000		475.000
Reservation Charge (\$MMBtu) \$ 2.055 \$ 0.252 \$ 0.252 \$ 0.252 \$ 0.252 \$ 0.252 \$ 0.252 \$ 0.252 \$ 0.252 \$ 0.252 \$ 0.255 \$ 0.255 \$ 0.255 \$ 0.255 \$ 0.255 \$ 0.255 \$ 0.255 \$ 0.255 \$ 0.255 \$ 0.255 \$ 0.256 \$ 0.256 \$ 0.256 \$ 0.256	MDQ (MMBtuday)		175,000		175,000		175,000	1.	1/5,000		175,000		175,000		110,000
MDQ on Transco 85 to Company B (\$MMBtu) (grossed up for Company B Fuel) 180,897 0.252 \$ 0.252 \$ 0.252 \$ 0.252 \$ 0.252 \$ 0.252 \$ 0.252 \$ 0.252 \$ 0.252 \$ 0.252 \$ 0.252 \$ 0.252 \$ 0.252 \$ 0.252 \$ 0.252 \$ 0.256 \$ 0.256 \$ 0.258 \$ 0.258 \$ 0.258 \$ 0.258 \$ 0.258 \$ 0.258 \$ 0.258 \$ 0.258 \$ 0.258 \$ 0.258 \$ 0.258 \$ 0.258 \$ 0.258 \$ 0.258 \$ 0.258 \$ <td< td=""><td>Reservation Charge (\$/MMBtu)</td><td>\$</td><td>2.055</td><td>\$</td><td>2,055</td><td>15</td><td>2.055</td><td> \$</td><td>2.055</td><td>\$</td><td>2.055</td><td>\$</td><td>2.055</td><td>\$</td><td>2.055</td></td<>	Reservation Charge (\$/MMBtu)	\$	2.055	\$	2,055	15	2.055	\$	2.055	\$	2.055	\$	2.055	\$	2.055
Transco 85 to Company B Reservation Charge (\$/MMBtu) \$ 0.252 \$ 0.255 0.265 \$ 0.256 <td>MDQ on Transco 85 to Company B (\$/MMBtu) (grossed up for Company B Fuel)</td> <td></td> <td>180.897</td> <td></td> <td>180.897</td> <td>Į –</td> <td>180.897</td> <td></td> <td>180.897</td> <td></td> <td>180.897</td> <td></td> <td>180.897</td> <td></td> <td>180,897</td>	MDQ on Transco 85 to Company B (\$/MMBtu) (grossed up for Company B Fuel)		180.897		180.897	Į –	180.897		180.897		180.897		180.897		180,897
Instruction of a content of the con	Transco 85 to Company B Reservation Charge (\$/MMBtu)	¢	0.252	e	0.252	le .	0 252	e .	0 252	ls .	0 252	15	0 252	\$	0.252
Capacity Addition 4 MDQ (MMBtu/day) 87,500 87	rances of the company is reported an ondrige (within the		0.202	<u> </u>	0.202	⊢ •	0.202	-	0.202	ŀ ⊷	0.202	۲Ť-			
Capacity Addition 4 MDQ (MMBtu/day) 87,500 87										1		1			
MDQ (MMBtu/day) 87,500 90,449 90,4	Capacity Addition 4											ļ			
Reservation Charge (\$MMBtu) \$ 2.107	MDQ (MMBtu/day)		87,500		87,500		87,500		87,500		87,500		87,500		87,500
MDQ on Transco 85 to Company B (\$/MMBtu) (grossed up for Company B Fuel) 90,449	Reservation Charge (\$/MMBtu)	\$	2.107	\$	2.107	\$	2.107	\$	2.107	\$	2.107	\$	2.107	\$	2.107
Transco 85 to Company B Reservation Charge (\$/MMBtu) \$ 0.258 \$ 0.256 \$ 0.255 \$ 0.265 \$ 0.265 \$ 0.265 \$ 0.265 \$ 0.265	MDQ on Transco 85 to Company B (\$/MMBtu) (prossed up for Company B Fuel)		90.449		90.449		90.449		90.449	ł	90.449		90.449		90,449
Capacity Addition 5 MDQ (MMBtu/day) 175,000 </td <td>Transco 85 to Company B Reservation Charge (\$(MMBtu))</td> <td>e</td> <td>0.258</td> <td>e</td> <td>0.258</td> <td>e</td> <td>0.258</td> <td>s</td> <td>0.258</td> <td>l e</td> <td>0.258</td> <td>s</td> <td>0 258</td> <td>\$</td> <td>0.258</td>	Transco 85 to Company B Reservation Charge (\$(MMBtu))	e	0.258	e	0.258	e	0.258	s	0.258	l e	0.258	s	0 258	\$	0.258
Capacity Addition 5 MDQ (MMBtu/day) 175,000 180,897 175,000	Transce certe Company of Reservation Onlinge (WWWData)	Ψ	0.230			*	0.200	₩	0.200	<u>⊢</u>	0.200	+*	0,400	<u>۴</u>	01200
Capacity Addition 5 MDQ (MMBtu/day) 175,000 180,897 175,000		F													
MDQ (MMBftu/day) 175,000 180,897 175,000 175,0	Capacity Addition 5														
Reservation Charge (\$MMBtu) \$ 2.159	MDQ (MMBtu/day)		175,000		175,000		175,000		175,000		175,000		175,000		175,000
MDQ on Transco 85 to Company B (\$/MMBtu) (grossed up for Company B Fuel) 180,897 175,000 180,897 180,897 180,897 180,897 180,897 180,897 180,897	Reservation Charge (\$/MMBtu)	\$	2.159	\$	2.159	\$	2,159	\$	2,159	\$	2.159	\$	2.159	\$	2.159
Transco 85 to Company B Reservation Charge (\$/MMBtu) S 0.265 \$	MDO on Trapson 85 to Company B (\$/MMBb)) (grossed up for Company B Fuel)		180 897	F .	180 897	1	180 897	l .	180 897	[·]	180 897	· ·	180.897		18D.897
Capacity Addition 6 MDQ (MMBtu/day) 175,000 180,897 180,897 180,897 180,897 180,897 180,897 180,897 180,897 </td <td>Transco 85 to Company & Reservation Charge (\$64MPtu)</td> <td>e</td> <td>0.065</td> <td>e</td> <td>0.265</td> <td>l e</td> <td>0.265</td> <td>¢</td> <td>0.265</td> <td>¢</td> <td>0.265</td> <td>e</td> <td>0.265</td> <td>¢</td> <td>0.265</td>	Transco 85 to Company & Reservation Charge (\$64MPtu)	e	0.065	e	0.265	l e	0.265	¢	0.265	¢	0.265	e	0.265	¢	0.265
Capacity Addition 6 MDQ (MMBtu/day) 175,000 180,897	Thanso os to company b Reservation Charge (#####Did)	3	0,203	<u> </u>	0,200	┟╩──	0.200	+	0,200		0.200	<u> </u>	0.200	~	0,200
Capacity Addition 6 Capacity Addition 6 175,000 180,897 180,897 180,897 180,897 180,897 180,897 180,897 180,897 180,897 180,897 180,897 180,897 180,897 180,897 180,897 180,897 180,897 180,897 180,897 <th< td=""><td></td><td></td><td></td><td></td><td></td><td>ł</td><td></td><td></td><td></td><td></td><td></td><td></td><td></td><td></td><td></td></th<>						ł									
MDQ (MMBtu/day) 175,000 180,897 180,897 180,897 180,897 180,897 180,897 180,897 180,897 0.271 0.271 0.271 0.271	Capacity Addition 6											1			
Reservation Charge (\$/MMBtu) \$ 2.213	MDQ (MMBtu/day)	1	175,000		175,000		175,000		175,000		175,000		175,000		175,000
MDQ on Transco 85 to Company B (\$/MMBtu) (grossed up for Company B Fuel) 180,897	Reservation Charge (\$/MMBtu)	\$	2,213	\$	2,213	\$	2,213	\$	2.213	\$	2,213	\$	2.213	\$	2.213
Transco 85 to Company B Reservation Charges \$ 0.271	MDD on Transco 85 to Company B (\$/MMRtu) (grossed up for Company B Eucl)		180.807	۱°	180 907	1	180 897	Ť	180 897	Ť	180 897	ľ	180 897		180 897
Annual Cost of Reservation Charges \$ 951,235,004 \$ 948,636,002 \$ 948,636	Transa of Hardoo of to Company D (priminital (grossed up to Company D Fuer)		00,097		0.037		0.051		00,037		0 274		0.274	e	0.274
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	Transco os to Company B Reservation Charge (\$(MIMBtu)	3	0.271	1.	0.271	3	0.2/1	\$	0,271	•	0.271	\$	0,271	9	0.271
Annual Cost of Reservation Charges \$ 951,235,004 \$ 951,235,004 \$ 948,636,002 \$ 948,036,002 \$ 948,002 \$ 948,002 \$ 948,002 \$ 948,002 \$ 948,002 \$ 948,002 \$ 948,002 \$ 948,002				i											
	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.

[Year		2047	-	2048	!	2049	T	2050		2051	Î.	2052		2053
	Company B Proposed Rate - Escalated at 2.5% per year 1/2/	\$	3.717	\$	3.810	s	3,905	5	4.003	\$	4.103	\$	4,206	\$	4.311
ьI	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
.				Ì				1							
Î	Company B Base Proposal					1									
	Company B MDQ (MMBtu/day)		400,000	1	400,000	Į	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	Ι.	413,479	Ι.	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	5	0.200
	• • • • • • • •														
	Capacity Addition 1			1			07.500		07 600		07 500		97 500		87 600
	MDQ (MMBtu/day)		87,500		87,500		87,300		67,000		1066		1 056	•	1 956
	MDO on Transport Sta Company D (\$000 Bbs) (meaned up for Company D Fuel)	э	1.900	3	1.900	•	00.440	•	0.440	P	00.6.1 QAA 00	°.	00.440	*	90 449
	Transco 85 to Company B Deservices Charge / (2010Phu)		90,449		90,449	l e	90,449	l e	0,445	e le	0 740	e	0 240		0 240
	Transco os lo company B reservation charge (s/wiwblu)	<u> </u>	0.240	-	0.240	1	0.240	<u> •</u>	0.240	1	0.240	<u> </u>	0.240	Ŷ	0.240
	Capacity Addition 2														
	MDQ (MMBh/day)		87 500		87.500		87 500	1	87.500		87.500	1	87.500	1	87,500
	Reservation Charge (\$/MMBtu)	s	2 005	s	2 005	s	2.005	İs	2.005	\$	2.005	\$	2.005	\$	2.005
	MDQ on Transco 85 to Company B (\$/MMBtu) (prossed up for Company B Fuel)	•	90.449	ľ	90,449		90,449	1	90,449	·	90,449	Ľ	90,449		90,449
	Transco 85 to Company B Reservation Charge (\$/MMBtu)	\$	0.246	s	0.246	\$	0.246	\$	0.246	\$	0,246	\$	0.246	\$	0.246
		-		<u> </u>		<u> </u>		<u> </u>							
	Capacity Addition 3														
	MDQ (MMBtu/day)		175,000		175,000		175,000		175,000		175,000		175,000		175,000
Į	Reservation Charge (\$/MMBtu)	\$	2.055	\$	2.055	\$	2.055	\$	2,055	\$	2.055	\$	2.055	\$	2.055
I	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
										1					
	Capacity Addition 4					1					07 500		07.500		07 500
	MDQ (MMBRu/day)		87,500		87,500		87,500		87,500		87,000	æ	37,300	e	2 107
	Reservation Charge (\$/MMBtu)	\$	2.107	1.2	2,107	•	2.107	>	2.107	3	2.107	э	2.107	ъ	2.107 60.449
	Transco 95 to Company B Personation Charge (\$94419tu)	e	90,449		90,449	e	90,449	l e	90,449	e	0 258	\$	0 258	s	D 258
ŀ		•	0.200		0.250	1.	0.200	┝╩──	0.200	╞┻	0.400		0.200	Ť	0.200
	Capacity Addition 5														
ľ	MDQ (MMBtu/day)		175.000		175.000		175.000		175,000		175,000		175,000		175,000
ļ	Reservation Charge (\$/MMBtu)	s	2.159	s	2.159	\$	2.159	\$	2.159	\$	2.159	\$	2.159	\$	2.159
ł	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
I	Transco 85 to Company B Reservation Charge (\$/MMBtu)	\$	0.265	5	0.265	\$	0,265	\$	0.265	\$	0,265	\$	0.265	\$	0,265
ſ]							Í
	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	æ	180,897
ŀ	Fransco Bo to Company B Reservation Charge (\$/MMBtu)	\$	0.271	\$	0.271	\$	0.271	L.»	0.271	12	0.271	3	0,271	3	0.271
1											040 626 000		054 025 004	*	948 636 002
1	Annual Cost of Reservation Charges	\$	948,636,002	5	851,235,004	12	948,535,002	1.2	948,636,002	F 🎙 🗌	948,636,002	•	951,239,004	4	340,030,00Z

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.

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

			Fuel Gas Reta	lined on Comp	any B System		Fuel Gas Retain	ved on Lateral fro	m Transco 8	to Company B		Calculated Cos	st of Fuel Gas	
		Proposed	Average	Annual			Contract							
	FPL Natural	Contract	Load	Throughput	Company B	Company B	MDQ	Annual	Projected	Laterai		Basis to		Annual
	Gas Demand	MDQ on	Factor for	on	Fuel	Fuel Gas	Lateral	Throughput	Lateral	Fuel Gas	Henry Hub	Transco	Unit Cost	Cost of
	Served	Company B	New Capacity	Company B	Rate	Retained	Extension	on Lateral	Fuel Rate	Retained	Cost of Gas	Zone 4	of Fuel Gas	Fuel Gas
Year	(MMBtu/day)	(MMBtu/day)	(%) 1/	(MM8tu)	%	(MMBtu)	(MMBtu/day)	(MMBtu)	% 2/	(MMBtu)	(\$/MMBtu) 3/	(\$/MMBtu) 4/	(\$/MMBtu)	\$
Column	. 1	2	3	4	5	6	7	8	9	10	11	12	13	14
					FGT Phase	10-1 A (/ A - 1		0-171 days in	See	10-1 0 / / 0 O	Rea Fratesta	See Fratrate		Col 12 t (Col
Course	FPL Load	0.014	Con Fostante	Can Frankaska	Vill Filing -	[COL47 (1- COL	COI 27 [1 - COI	COL/ Cays In	roothote		See roomote	A/	12	6 + Col 10)
Source	Forecast	001	See Footnote	See Foothote		8}]-C014	6	year - cors	2	211-0010	37	* 0.0536	¢ 0.4902	47 COI 10)
2012	50,000	50,000	0%	-	3.26%	4 400 000	51,685	-	0.30%	103 203	a 8,130 e 8,130	\$ 0.0525 \$ 0.0525	3 0,1023	90 \$10 111 164
2013	400,000	400,000	54%	32,916,000	3.20%	1,109,222	413,479	34,020,222	0,30%	102,303	0.293 F 9.602	a 0,0020 ¢ 0,0020	\$ 9.3433 \$ 9.7440	\$27,496,720
2014	400,000	400,000	59% 70%	404 757 P00	3.20%	2,070,0101	413,479	108 297 099	0.30%	205,700	\$ 0,092 \$ 0,107	\$ 0.0525 \$ 0.0525	\$ 0.7445	\$35 646 988
2010	400,000	400,000	7276	111 114 000	3.2076	3,330,168	413,479	114 858 383	0.30%	345 612	\$ 9,692	\$ 0.0525	\$ 97440	\$39,853,091
2010	400,000	400,000	70%	114,000	3.20%	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	403,000	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	\$144,050,449
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%	10,964,682	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	5 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	\$ 10.6044	\$201,790,033
2035	1,187,500	1,187,500	/5%	325,078,125	3.25%	10,954,669	1,227,517	330,032,794	0.30%	1,011,132	\$ 17,146 \$ 17,404	\$ 0.0525 ¢ 0.0525	\$ 17.2000	\$200,010,837
2036	1,187,500	1,187,500	/5%	325,968,750	3.25%	10,984,682	1,227,517	330,933,932	0,30%	1,013,902	¢ 17.491	\$ 0.0525	\$ 17.0400	\$210,487,420
2037	1,187,500	1,107,500	750/	323,078,125	3,20%	10,954,009	1 227,517	336,032,784	0.30%	1,011,132	\$ 19.109	\$ 0.0525	\$ 18 2501	\$218 376 811
2030	1,187,500	1 187 500	75%	325,078,125	3.26%	10,954,009	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	\$268,722,853
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	ə 24.491	> 0.0525		3293,D/9,462

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.

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Total Annual Revenue Requirements for Florida EnergySecure Line Project

								Value of Incr	emental Capat	ity Purchases				
1	RR to offeet Project Investment Incremental Capacity Required			auired	Cat	e A - Current M	anket	Case B -	FGT Phase Id	Max Rate	Case C - No	Spot Market Co	pacity Value	
	Cest of Off-			1			ļ							
	Site	Annual Florida	Peak Day	Florida	Incremental									
	Compression	EnergySecure	Demand Served	EnergySecure	Capecity to be	Unit Cost of	Cost of Spat	Total Cost of	Unit Cost of	Cost of Spet	Total Cost of	Unit Cent of	Cost of Spot	Tetal Cost of
	at CCEC	Line Revenue	by incremental	Line Project	Purchased in	Spot Mariest	Market	Energy Secure	Spot Market	Markat	Energy Secure	Spot Market	Market	Energy Secure
	Facility	Requirements	Capacity	Capacity	Spot Market	Capacity	Capacity	Line Project	Capacity	Capacity	Line Project	Capacity	Capacity	Une Project
Year	(\$)	(1)	(HAN Bluiday)	(MRBtu/day)	(MMBtu/day)	(\$IMMBty)	(5)	(5)	(\$/MM8tu)	(\$)		(\$ANIMENU)	(\$)	(7)
Column	i	2	3	4	6		7	3	3	10	11	12	13	14
	FPL Revenue	FPL, Revenue					1						0-1510-142	0-114 0-124
-	Requirements	Kequirements		See roomote	Goeumin 3 -	See Foomete	COLP. COLP.		366 - 000000			a/	- dawn	Col 13
Seurce	Analysis 1/	ADDIVSIS 1/	300 F 000000 2/	<u> </u>	Gajurma 4	<u> </u>	days	0017		ays to	00110		0092	50 50
Sept 1, 2012 - Dec 1, 2012	1 1	50		1		5 0.4614	50		3 1,302/	5 61 474 701	51 474 701	č		1 50
Dec 1, 2012 - Jan 1, 2012	4700 880	50	30,000		30,060	S 0,4614	Read 676	8428,142	a (,305) c 4 6867	87 808 888	S1 507 275	è		\$700.086
Jan 1, 2013 - March 1, 2012	\$750,000	50	30,000		60,000	a 0,4014	3010,010	51,317,304	C 1 6857	\$14 588 440	54,775,812	ĩ		\$2185.192
March 1, 2013 - Sept 1, 2013	\$2,165,192		30,000	1 .	30,000	5 0.4614	59 207 400	\$0,430,072	3 1.505/	\$78,506,440	\$20 040 400	2	1 2	\$1 080 720
Dept 2013 - Dec 1, 2012	1,000,720		200,000	l	200,000	6 0.48%	\$3,347,445	\$3,857,010	¢ 1.6857	\$11 305 041	S11 874 195	š		\$368 157
Ion 1 2014 - March 1 2014	5000,101	CAR 100 008	230,000	804 714	230,000	5 0.4814	45,205,102	647 014 201	\$ 15857	51	547 014 291	š	s	\$47.014.291
March 1 2014 - June 1 2014	\$1,005,224	\$72 305 196	250,000	590 718		\$ 0.4614		\$73,310,419	\$ 1,5857		\$73 310 419	š	sc	\$73,310,419
June 1 2014 - Jan 1 2015	\$7,338,238	\$168 188 172	400.000	508,718	a .	5 0.4614	s	\$170.526.410	\$ 1,5857	50	\$170,528,410	ŝ	50	\$170,526,410
2015	\$3,820,359	\$276,948,894	400.000	596,718	0	5 0,4729		\$250,758,254	\$ 1,5857	50	\$280,769,254	ŝ	\$0	\$280,769,254
2016	\$3,663,294	\$265,593,54	400.000	596,718	i a	S 0,4846	i so	\$259,256,843	\$ 1,5857	50	\$269,255,543	s	\$0	\$269,258,843
2017	\$3,515,900	\$254,973,624	400.000	598,718	5	5 0,4989	50	\$258,489,524	\$ 1,5857	50	\$258,489,524	ls .	50	\$258,489,524
2018	\$3.377,300	\$245.017.656	400,000	596,718	0	\$ 0.5093	i sc	\$248,394,987	\$ 1,5657	\$0	5248 394 967	5	\$0	\$248,384,987
2019	\$3,244,770	\$235,657,691	400.000	596,718	l o	\$ 0.5220	s	\$235,902,552	\$ 1.5857	50	\$238,902,862	\$	\$0	\$238,902,602
2020	\$3,114,186	\$226,719,020	400,600	596,718	0	\$ 0.5351	\$	\$229,833,207	\$ 1,5857	\$0	\$229,833,207	\$	50	\$229,833,207
2021	\$2,983,600	\$217,920,487	487,500	596,718	0	\$ 0.5485	\$	\$220,904,087	\$ 1,5857	\$0	\$220,684,087	s	j SC	\$220,904,087
2022	\$2,853,094	\$209,125,72	575,000	596,718	0	\$ 0,5822	\$	\$211,978,818	\$ 1.5657	\$0	\$2\$1,978,818	\$	SC SC	\$211,978,818
2023	\$2,722,607	\$223,301,25	750,000	800,000	0	\$ 0.5782	s 🔊	\$226,023,862	\$ 1.5857	\$0	\$226,023,662	\$	\$C	\$226,023,862
2024	\$2,592,232	\$229,693,22	837,500	1,000,000	0	\$ 0,5908	\$	\$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	¥	\$277,501,341	\$ 1.5657	\$0	\$277,501,341	5	\$	\$277,501,341
2026	\$2,331,139	\$252,934,831	1,187.500	1,250,000	0	\$ 0,6205	5	\$265,265,970	\$ 1.5857	\$0	\$265,265,970	\$	SI SI	\$265,265,970
2027	\$2,200,713	\$250,854,77	1.187,500	1,250,000	0	\$ 0.6360	j \$4	\$252,855,491	\$ 1,5657	50	\$252,855,491	\$	50	\$252,855,491
2028	\$2,087,741	\$238,585.92	1,167,500	1,250,000	0	\$ 0.6519	5	\$240,683,666	\$ 1.5857	\$0	\$240,683,666	5	5	5240,683,656
2029	\$2,010,100	\$227,942,53	1,187,500	1,250,000	0	\$ 0.6652	\$	\$229,962,633	5 1.5657	\$0	\$229,952,633	\$	1 50	\$229,952,033
2030	\$1,950,040	5215,646,50	1,107,500	1,250,000	0	\$ 0.6650	1 50	\$221,700,541	\$ 1.5857	50	\$221,798,541	2	9 9	\$221,180,941
2031	\$1,869,838	5213,033,553	1,187,500	1,250,000	a a	5 0,7021	X	\$214,923,391	\$ 1,5857	30	5214,923,391	2	1 21	2008 081 000
2032	51,829,636	\$200,251,971	1,187,500	1,250,000		\$ 0.7196		\$200,001,000	\$ 1,909/ • 1,505/	30	5208,061,000		30	1 \$200,081,000
2033	\$1,700,101	\$193,451,99,	1,101,500	1,250,000		5 0.7376	9	5201,221,083	÷ 1,505/		B104 402 000	12	an	\$104 407 008
2034	\$1,109,002	\$192,083,03	1,107,500	1 250,000		\$ 0,7501 \$ 0,750		\$187 500 270	S 1 8857		\$187 500 270		2	5187 590 270
2035	\$1 589 401	\$179 224 ATH	1 187 500	1,250,000	1 1	\$ 07043	1 8	\$160 813 808	8 1 5857	50	\$180 813 805	ś	S S	\$180,813 800
2037	\$1 520 107	\$177.473.10	1 187 500	1,250,000		\$ 0.8142		\$174.002.301	\$ 1,5857	30	\$174,002,391	5	50	\$174.002 391
2038	\$1,489,186	\$165.836.44	1,187,500	1,250,000	0	\$ 0.8345	9	\$187,205,870	\$ 1,5657	50	\$167,305,870	s	SC SC	\$187,305.870
2039	\$1,408,191	\$159,459,756	1,187,500	1 250 000	i o	\$ 0.6554	<u> </u>	\$160,858,941	\$ 1,5857	50	\$180,858,941	s	Ś	\$160,888,941
2040	\$1,349,213	\$153,544,763	1,187,500	1,250,000		\$ 0.6795	ŝ	\$154,893,976	\$ 1,5857	50	\$154,893,976	\$	s	\$154,893,976
2041	\$1,269,253	\$148,166,16	1,167,500	1,250,000	0	\$ 0,8987	l s	\$149,455,418	\$ 1,5857	5	\$149,455,418	\$	\$4	\$149,455,418
2042	\$1,229,311	\$143,027,934	1,167,500	1,250,000	0	S 0.9212	s s	\$144,257,250	\$ 1,5857	\$0	\$144,257,250	5	\$4	\$144,257,250
2043	\$1,169,387	\$137,898,76	1,187,500	1,250,000	0	\$ 0.9442	5	\$139,068,151	\$ 1.5857	\$0	\$139,068,151	5	50	\$139,068,151
2044	\$1,109,483	\$132,778,661	1,167,500	1,250,000	0	\$ 0.9578	S 2	\$133,685,349	\$ 1.5857	\$0	\$133,886,349	\$	51	\$133,866,349
2045	\$1,059,666	\$127,688,48	1,187,500	1,250,000	0	\$ 0,8920	\$	\$128,728,150	\$ 1,5857	\$0	\$128,728,150	\$	\$4	\$128,728,150
2046	\$1.009.876	\$123,256,23	1,187,500	1,250,000	0	S 1.0168	\$	\$124,268,112	\$ 1,5857	\$0	\$124,260,112	5	50	\$124,266,112
2047	\$960,103	\$118,853,98	1,187,500	1,250,000	C C	\$ 1.0422	50	\$118,814,090	\$ 1,5857	\$0	\$119,814,090	\$	\$	\$119,814,090
2048	\$910,351	\$114,481,98	1,187,500	1,250,000	0	\$ 1.0563	50	\$115.372.335	\$ 1.5857	\$0	\$115,372,335	5	\$	\$115,372,335
2049	\$880,820	\$110,080,48	1,187,500	1,250,000	0	\$ 1,0950	\$	\$110,941.107	\$ 1,5857	\$0	5110,941,107	\$	50	\$110,941,107
2050	\$810,911	\$105,709,75	1,187,500	1,250,000	0	\$ 1,1224	\$	\$106,520,670	\$ 1.5657	\$0	5108,520,870	s	\$	\$108,520,670
2051	\$781,225	\$100,974,59	1,187,500	1,250,000	0	\$ 1,1504	\$	\$101,735,620	\$ 1,5867	\$0	\$101,735,820	5	\$	\$101,735,820
2052	\$711,562	\$96,241,38	1,187,500	1,250,000	0	\$ 1.1742	\$	\$96,952,924	\$ 1.5657	\$0	\$96,952,924	5	\$	3 \$95,952,924
2053	\$	\$91,510,10	1,187,500	1.250,000	0	\$ 1.2087	5	A \$91,510,109	5 1.5857	\$0	391,510,109	5	3	4 \$91,510,109

¹⁰ Ansuel Revenue Requirements for 2013 and 2014 allocated pro rate to each listed portion of calendar year. For the years 2015 and beyond, the samuel revenue requirements is as provided by FPL.

²² Peak Day Damiand for this 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 langth and has a peak demand of approximately 30,000 MMBhu/day during the line three months of testing. Thus, the analysis, will 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 MMBhu/day for the line) three months of testing. Thus, the analysis, will 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 MMBhu/day for the line) three months of testing (Dacamber 2012 - Fabruary 2013 for CCEC and March-May 2014 for RBEC), 30,000 MMBhu/day for the previous three months of testing (Dacamber 2012 - Fabruary 2013 for CCEC and Decomber 2013 - Fabruary 2014 for RBEC), 30,000 MMBhu/day for the previous three months of testing (Dacamber 2012 - Fabruary 2013 for CCEC and Decomber 2013 - Fabruary 2014 for RBEC), 30,000 MMBhu/day for the previous three months of testing (Dacamber 2012 - Fabruary 2013 for CCEC and Decomber 2013 - Fabruary 2014 for RBEC), 30,000 MMBhu/day for the plant 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 FPI, a Low Forecast or projected capacity purchased under Company 6 capacity purchases canade.

*Fortide EnergySecure Line Capacity for Initial years of project based upon the capacity of the Upstream Pipeline Project to deliver to EnergySecure Line (800,000 MMShu/day) tass fuel retention required on EnergySecure Line at 0,55%. After expensions, communiting in 2023, capacity is based upon proposed EnergySecure Line capacity after each expension project is placed in service.

⁴⁴ Unit cost of spot market capacity based upon average price paid by FPL for secondary or interruptible transportation capacity into Floride (\$0.4814AMMBItu) during 2008. As conservative assumption, this value is assumed constant through 2014 and escalated of a rat of 2.5% per year thereafter.

²⁹ 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.

¹⁰ Assumes significant excess capacity sveilable 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.

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Attachment III B

Year	2013	2014	2015	2016	2017	2018	2019
Company E Proposed Rate - Escalated							
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 (MMBlu/day)		402,212	402,212	402,212	402,212	402,212	402,212
<u>Company E Pipeline Proposal</u> MDQ (MMBtu/day) Upstream Pipeline Project Res. Fee (\$/MMBtu)		600,000	600,000	600,000	600,000	600,000	600,000
Capacity Addition 1 MDQ (MMBtu/day) Reservation Charge (\$/MMBtu)		-	-	-	-	-	-
Capacity Addition 2 MDQ (MMBtu/day) Reservation Charge (\$/MMBtu)			-	-	-	4	
Capacity Addition 3 MDQ (MMBtu/day) Reservation Charge (\$/MMBtu)		-	-	_	-	-	-
Capacity Addition 4 MDQ (MMBtu/day) Reservation Charge (\$/MMBtu)		-	-	-	-		
Annual Cost of Reservation Charges							

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.

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

Year	2020	2021	2022	2023	2024	2025
Company E Proposed Rate - Escalated			····			
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
Company E Pipeline Proposal MDQ (MMBtu/day) Upstream Pipeline Project Res. Fee (\$/MMBtu)	600,000	600,000	_600,000	600,000	600,000	600,000
Capacity Addition 1 MDQ (MMBtu/day) Reservation Charge (\$/MMBtu)		-		15 7,040	157,040	157,040
Capacity Addition 2 MDQ (MMBtu/day) Reservation Charge (\$/MMBtu)	_	-	-		89,518	89,518
Capacity Addition 2						
MDQ (MMBtu/day) Reservation Charge (\$/MMBtu)						
Capacity Addition 4 MDQ (MMBtu/day)	-	-	-	-	-	
Reservation Charge (\$/MMBtu)	\$ -	\$ -	\$ -	\$	\$ -	
Annual Cost of Reservation Charges						

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.

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Үеаг	2026	2027	2028	2029	2030	2034
Company E Proposed Rate - Escalated			1010		7000	2001
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 (MMBlu/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) Upstream Pipeline Project Res. Fee (\$/MMBtu)	600,000	600,000	600,000	600,000	600,000	600,000
Capacity Addition 1 MDQ (MMBtu/day) Reservation Charge (\$/MMBtu)	157,040	157,040	157,040	157,040	157,040	157,040
Capacity Addition 2 MDQ (MMBtu/day) Reservation Charge (\$/MMBtu)	89,518	89,518	89,518	89,518	89,518	89,518
Capacity Addition 3 MDQ (MMBtu/day) Reservation Charge (\$/MMBtu)	183,347	183,347	183,347	183,347	183,347	183,347
<u>Capacity Addition 4</u> MDQ (MMBtu/day) Reservation Charge (\$/MMBtu)	178,008	178,008	178,008	178,008	178.008	178,008
Annual Cost of Reservation Charges						·

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.

 $2\prime$ 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.

Year	2032	2033	2034	2035	2036	2037
Company E Proposed Rate - Escalated						
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
		1				
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)						
Capacity Addition 1				100.040	455.040	(57.040
MDQ (MMBtu/day)	157,040	157,040	157,040	157,040	157,040	157,040
Reservation Charge (\$/MMBtu)				-		
Canaalfe, Addition 7						
	90 519	PO 619	913.09	90 519	80 519	80 518
MDQ (MMDDDDdy)	09,010	08,010	03,010	010,60	08,010	09,510
Capacity Addition 3						
MDQ (MMBtu/dav)	183.347	183.347	183.347	183,347	183.347	183.347
Reservation Charge (\$/MMBtu)						
Capacity Addition 4						
MDQ (MMBtu/day)	178,008	178,008	178,008	178,008	178,008	178,008
Reservation Charge (\$/MMBtu)						
Annual Cost of Reservation Charges						

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.

 $2\prime$ 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,

Year	2038	2039	2040	2941	2042	2043
Company E Proposed Rate - Escalated						
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)						
Capacity Addition 1						
MDQ (MMBtu/day)	157,040	157,040	157,040	157,040	157,040	157,040
Reservation Charge (\$/MMBtu)						
Comparise Addition of						
MDQ (MMBlu/day)	89,518	89.5181		89,518	89.518	89.518
Conseity Addition 2						
	192 347	182 247	193 347	192 247	192 247	193 347
Reservation Charne (\$/MMBtu)	100,047	100,077	100,047	100,047	100,047 [100,047
robbischer ontrigo (entranbic)						
Capacity Addition 4						
MDQ (MMBtu/day)	178.008	178 008	178 008	178 008	178 008	178 008
Reservation Charge (\$/MMBtu)				1.0,000	1101000	
Annual Cost of Reservation Charges						

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.

Year	2044	2046	2046	2047	2048	2049
Company E Proposed Rate - Escalated						
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
<u>Company E Pipeline Proposal</u> MDQ (MMBtu/day) Upstream Pipeline Project Res. Fee (\$/MMBtu)	600,000	600,000	600,000	600,000	600,000	600,000
Capacity Addition 1 MDQ (MMBtu/day) Reservation Charge (\$/MMBtu)	157,040	157,040	157,040	157,040	157,040	157,040
Capacity Addition 2 MDQ (MMBlu/day) Reservation Charge (\$/MMBtu)	89,518	89,518	89,518	89,518	89,518	89,518
Capacity Addition 3 MDQ (MMBtu/day) Reservation Charge (\$/MMBtu)	183,347	183,347	183,347	183,347	183,347	1 83, 347
<u>Capacity Addition 4</u> MDQ (MMBtu/day) Reservation Charge (\$/MMBtu)	178,008	178,008	178,008	178,008	178,008	178,008
Annual Cost of Reservation Charges						

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.

 $2\prime$ 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.

Year	2050	2051	2052	2053
Company E Proposed Rate - Escalated				
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	000 000	600 000	600.000
Upstream Pipeline Project Res. Fee (\$/MMBtu)		000,000	200,000	000,000
Capacity Addition 1				
MDO (MMBtu/day)	157 040	157.040	157.040	157 040
Reservation Charge (\$/MMBtu)	157,040 [157,040	157,040]	107,040
Concelle & dilition o				
Beconvision Charge (\$MMAD:)	89,518	89,518	89,518	89,518
			1	
Capacity Addition 3			İ	
MDQ (MMBtu/day)	183,347	183,347	183,347	183,347
Reservation Charge (\$/MMBtu)				
Capacity Addition 4				
MDQ (MMBtu/day)	178.008	178 008	178 008	178 009
Reservation Charge (\$/MMBtu)	170,003	170,000 [178,000 [170,000
Annual Cost of Becomution Channes				

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

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11			_	Fuel Gas Bu	rned on Energ	ySecure Line	Fuel Gas	Retained by Up	streent Plooff	ne Protect		Calculated C	ont of Funi flag		Hanna Abarrow	Illustine		Taut	
\mathcal{O}			Average	Gan		Fuel Gas	Projected	Americal	Usebra m	T	****	1		· · · · · ·	Condition of the second		COMING PTOLOCY	1 Clas	Unit Cost of
\odot	4	FFL	Lord	Transported	Floride	Consumed on	Contract \$20Q	Throughput	Plantone	Total					Americant	Opening .		upanesm	usage Charge
<u> </u>		Natural Gas	Factor for	on Florida	EnergySecure	Floride	On Unstrated	Unstraura	Present	Concernent of	1	Ganta Ja	1		Annae	Protine		Pipežno X.	per MMBtu
·	1	Demand	for new	EnergySecure	Line	EnergySecure	Pipeline	Pineline	Firm	Brand time	Manage Lands	Deals to		IRVINA	I would have	Proposed	Annual Cost	EnergySecure	Transported o
= 1		Served	Climicity	Line	Fund Rate	i ine	Deslant	Patrice	Defection	Policians.	Henry Hop	[lianseo	Unit Gost	Gost of	Upstream	Comm.	of Usage	Un#	Upstream PIL.
I	Year	(MMBhuklay)	(%) ^V	(MMRR atward)		Manager	All and a second	Project	INCINACOO	Destimate	Cost of Ga	Zona 4	Of Fuel Gas	Fuel Ges	Pipeline	Atte	Charges	Usage Costs	EnergySecur
	Caluma	1	1.4	Construction of Carly	<u> </u>	E LERINGER LIVERT	I Constanting of the	(MABAJyear)	<u> </u>	(MiMBtalyr)	(和))))(11))))))))))))))))))))))))))))))	(SANNERU) 3/	(\$/MMBtu)	(\$/Year)	(NINBtu/year)	(S/MIRBIN)	(S/Year)	(S/Year)	A STRATEGICS
	Catalan	·	2	3	4	6	•	7		1	10	11	12	13	+4	16	4.8		(Annual Oco)
i i		The same										1	(·····				Callana	<u> </u>	18
	-	FFC 1010			FPL-Collins		Col 1 * (1 +	Coll 6 * Coll 2 *	Company #	ICH7/R-CH			Col 10 + Col	Col 1124Col					
1	Source	1-241064558	Feethelm 1/	Footnoie 1/	Estimates	Cel 3* Cel 4	Col 4)	days in your	Bid	837-Cel 7	Footnets 2/	Footoote 3/	14	Secon .	0.49	R			
	2014	400,000	59%	85,422,800	0.55%	469.877	402.200	85 869 103						2 - Q4 2		Loosing 4	- 058 15	Col 13 + Cal 15	COI 17 / Col 3
	2015	400,300	72%	104,757,509	0.55%	576 166	402 200	108 191 044			0.004	• 0.0021	3 5.7449		25,892,123				
	2016	400,000	76%	111 114 000	0.5556	611 197	102 226	111 705 405			8 9,192	4 9,0925	\$ 9,2445		105,133,958				
	2017	400,000	76%	114 002 300	0.56%	877.013	402 300	11.740,427			3 9,612	\$ 0.0525	 S 9.744 0		115,725,127				
	2018	400,000	70%	115 486 300	A 4 5m	421,010	100.000	114,028,013			5 10.285	\$ 0.0525	3 10,3435		114,629,313				
	2019	400,000	7.00	114 445 400	0.007	030,170	402,200	110,121,475			\$ 11,090	3 0.0525	1 11,1426		118,121,475				
	2020	400,000	The	114,415,400	9.55%	029,285	492,200	115,044,685			\$ 12,089	\$ 0,0525	3 12.1420		115.044.685				
	2024	407,000	1029	111,670,500	0.03%	613,838	402,280	112,184,158			\$ 12,742	1 0.0525	5 12,7942	1	112 184 138				
	2021	401,000	10%	133,453,125	0.55%	735,992	490,181	134,187,117			\$ 12,997	\$ 0.0525	5 12 0490		434 187 117				
	2022	375,000	75%	157,400,250	0.85%	885,754	578,163	155,271,454			5 13,256	1 0.0525	4 13 3089		100,001,001				
1	2023	750,000	75%	205,312,500	0.93%	1,917,619	757,005	207.230.119			\$ 13.572	1 0.0516	8 61 8740		130,233,904				
	2024	837,500	75%	229,893,750	1.07%	2,459,853	646,461	232,353,813			\$ 19.704	0.0425			207,230,110				
	2025	1,012,500	75%	277,171,875	1.66%	4,884,206	1 429 611	287 856 681				3 0.0929	3 78.0444		232,303,013				
	2026	1,167.500	75%	325,078,125	1,89%	5 643 820	1 202 660	910 571 648			• 14,000	3 0,0525	¥ 14.1202		261,366,080				
	2027	1,187,500	75%	325.078.125	1.69%	5.493.820	1 201 800	730 871 845			a 14,343	\$ 0,0525	\$ 14,4015		336,571,945				
	2028	1,187,600	75%	325 685 750	1 69%	5 504 172	1,207,300	401.011.945			\$ 14,638	5 0.0925	\$ 14,6865		330,571,945				
- 1	2029	1,187,500	73%	326 078 125	6 100 100	5,000,012	1 007 000				\$ 14,928	¥ 0.0525	\$ 14.9812		331,477,822				
1	2030	1,107,500	75%	325 078 125	1 40%	8,409 800	1,007,000	330,011,943			\$ 15,227	\$ 0.0525	\$ 15.2797		330,571,945	1			
- 1	2031	1.167.500	75%	325 678 475	1	6 403 800	1,207,303	230,071,943			\$ 15,532	\$ 0,0525	\$ 15,5842		230,571,945				
	2032	1 187 500	794	334 464 783	1.459	3,483,620	1,207,309	330,571,945			\$ 15.842	\$ 0.0525	\$ 15,8948		330.671.845				
	2033	1 187 500	764	305,000,000	1,000,70	0,505,872	1,297,009	331,477,622]		J 10,159	\$ 0.6525	\$ 18,21 18	: .	331 477 822				
1	2014	1 187 500	707	445,074,128	1.074	5,493,820	1,207,669	830,571,945			\$ 14,482	\$ 0.0525	\$ 19,5348		330 571,945				
1	2016	1 1 1 7 500	1070	320,070,120	1,68%	8,493,820	1,207,569	\$30,571,945	1		2 18,612	1 0.0525	\$ 15.6544		\$30 571 845				
1	2016	1,107,000	7376	\$20,076,120	1,69%	5,493,620	1,207,509	330,571,946	1		\$ 17.14	\$ D.0625	5 17,2008		330 675 644	-			
	2030	1,187,500	75%	\$25,958,750	1.69%	5,505,672	1,207,569	331 477 622			\$ 17.491	5 0.0926	5 17 5436		331 /37 646				
	2037	1,187,500	75%	325,078,125	1.69%	6,483,820	1,207,589	330.571.846	1		5 17 But	1 0 00536	C 47 MIN		401/01/022				
	2030	1, 187, 500	75%	325,078,125	1,09%	5,493,820	1,207,569	330,571 945			\$ 18 199	5 0.0825	1 1000		330,371,946	1			
	2039	1,187.500	75%	325,076,125	1.89%	5,498,820	1,207,569	330.571.846			8 (8.68)	4 0,0020	10.0301		430,571,996				
	2040	1,187,500	75%	325,068,750	1.89%	5.508.872	1,207,569	331 477 622			8 68 69 6	4 0.0020	3 10.0140		330,971,946				
1	2041	1,187,509	76%	325,078,126	1,69%	5,493,820	1,207,589	330 571 945			F0.054	\$ 0,0023	3 10,3002		831,ATT,622				
	2042	1,167,600	75%	328,078,125	1.89%	5,495,820	1,207,589	330 571 646			9 10.011	3 0.0025	3 19.3636		330,571,945	-			
	2043	1.187,508	75%	325,078,125	1.59%	5 493 870	1 2072 5490	310 571 045			\$ 19,697	\$ 0,0525	\$ 19,7500		336,571,946				
	2044	1,167,500	75%	323,568,750	1.69%	5 108 872	1 907 580	1 0 10 0T 1 0 00			\$ 20.091	3 0.0628	 \$ 20.1439		330,571,945				
1	2045	1,187,500	75%	325 076 126	1 004	5,000,072	1,207,209	331 4/7.022			8 20,493	\$ 0.0625	\$ 20,5457		331,477,622				
1	2048	1 187 600	76%	375 675 645	1.0276	3,486,620	1,207,808	330,571,945			\$ 20,003	\$ 0,0525	\$ 20,9555		330,571 945				
1	2047	1 187 500	784	325 078 136	1.0976	0,493,420	1,207,559	330,671,945			S 21.321	\$ 0.0525	\$ 21,3738		\$30,571,945				
	2048	1 187 500	7634	40,010,125	1.09%	5,493,820	1,207,589	330,571,945			\$ 21,747	\$ 0,062.5	\$ 21,7000		330 571 944				
	2010	1,107,300	10%	323,968,750	1.50%	6,508,872	1,207,589	381 477 622			\$ 22.182	\$ 0.0525	\$ 22 73.48		311 477 612				
	2050	1,107,500	13%	325,078,125	1,69%	5,493,820	1,207,569	230,571,945			\$ 22,824	\$ 0.0575	5 22.8784		335 474 845				
1	2020	1,167,300	/5%	325,078,125	1.69%	5,403,820	1,207,569	330,571,845			\$ 23.87	S 0.0676	S 23 Hans		330 574 644				
1	2031	1,187,200	75%	325,076,125	1.09%	5,493,820	1,207,569	330,571,645			\$ 23.440	3 0.0504	1 27 5000		130,311,910				
	2052	1,187,500	75%	325,968,790	1.69%	\$,508,872	1,207,569	331,477,822			4 74.011	1 0 0000	4 4444		434,211,948				
	2022	1,187,600	75%	325,078,126	1.69%	\$ 493,820	1,207,569	330 571 BAL				0.0025	24.0031		331,477,622				
											24,491	1 0.0525	17 24.5432		230,571,945				

Attachment IV
<u>Projected Usage / Commodity Charges Incurred by FPL with Upstream Proefine / FPL Intrastate Pineline Projec</u>

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1/ Capacity usage for the years 2014 through 2020 as per PPL annual gas consumption projections for REEC and CCEC tacilities. Capacity usage for the years 2021 and beyond based upon assumed 76% capacity usage load factor.

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

3/ Basis differential between Henry Hub and Transco Station 65 equal to value included within PPL fuel price forecast published towersber 2008.

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

FPL Capacity Plosting Revenues Revenues Revenues Matural Gas Project Available 1 Init Hinit Holt from from from Fuel Delivery For Release Release Capacity Release Capacity Capacity Capacity Release Values Ralezzo Values Release Values Rolanse Requirements (MMBtu/day) Year (MMBILuiday) (MMRhulday (\$/MMEtu) 1\$1 /S/M MEthu (5) (\$/MMBtu **t\$**1 Column 3 4 7 8 5 9 Attachment III Attachment See Footnote Coi 4 * Col 3 * See Col 6 * Col 3 * Assume No. Col 8 * Col 3 A. Column 3 IIIA, Column 4 Col 2 - Col 1 Source 47 Value dava Enginete 7/ days in year days in year Sept 1, 2012 - Dec 1, 2012 D.4614 1.5857 Dec 1, 2012 - Jan 1, 2013 30.000 1.5857 so 04814 \$0 \$0 Jan 1, 2013 - March 1, 2013 50 \$0 \$0 30,000 1 5857 0.4614 88888888 March 1, 2013 - Seot 1, 2013 50.000 0.4614 50 1.5857 Sept 1, 2013 - Dec 1, 2013 200,000 0.4614 \$0 1.5657 sa Dec 1, 2013 - Jan 1, 2014 230.000 so 0.4614 sn 1,5857 lan 1, 2014 - March 1, 2014 596 718 \$34,308,784 230,000 366.718 04614 \$9,983.019 \$ 1.5857 Merch 1, 2014 - June 1, 2014 250,000 596,718 346,718 0.4614 \$14,717,765 1.5857 \$50,580,755 5 June 1 2014 - Jan 1 2015 400,000 596,718 196,718 0.4614 \$19,423,862 1,5857 \$66,754,264 2015 400,000 596.718 196,718 0.4729 1.585 \$33,957,721 \$113,858,572 2018 400,000 596,718 198,718 0,4848 1.5857 \$114,168,508 \$0 \$34,902,024 2017 400,000 590,718 196 718 \$ 0 4949 \$35,676,890 \$ 1 6867 \$113,856,572 2018 0,509 \$113,856,572 400.000 596,718 196,718 \$ \$36 568,751 1.5857 2019 596,718 400,000 196,718 ŝ 0,5220 \$37,482,970 1.6657 \$113,858,572 2020 400,000 596,718 195,718 0.5351 \$38,525,305 1.5857 \$114,168,500 2021 487,500 598,718 109,216 0,5485 \$21,884,117 1,5857 \$83,213,278 575,000 596,718 2022 0.5822 \$4,456,380 1,5857 \$12,569,984 21.718 2023 750,000 800,000 0.5762 \$10,516,113 \$ 50,000 1.6657 \$28 939 025 2024 837,500 1.000 000 162,500 0.5906 \$35, 127, 779 1.5857 \$94,309,508 . 2025 1.012.500 1.250.000 237,500 0.6054 \$52,480,334 1 5857 \$137,460,366 \$ 2026 1,187,500 1,250,000 62,500 0.6205 \$14,155,879 1.5857 \$30 173 781 2027 1,187,500 1,250,000 62,500 0.6360 \$14,509,776 1.5857 \$35,173,751 2028 1,187,500 1,250,000 62,500 0.6519 \$14,913,288 1.5857 \$38 272 ABR 5 2029 1,187,500 1,250,000 \$15,244,334 82 500 0.6682 1 5853 \$36,173,781 \$ \$ 2030 62.500 8 1.187.500 1,250,000 D 6850 \$15,625,442 1.5857 \$38,173,781 \$ 2031 1,187,500 1,250,000 62,500 0.7021 \$18,016,078 1.5857 \$36,173,781 \$ 2032 1,187,500 1,250,000 62,500 0,7198 \$18,461,457 1.5857 \$36,272,688 2033 1 187,500 1,250,000 62.500 0.7378 \$15,826,892 1.5857 \$36,173,781 5 2034 1,187,500 1,250,000 \$17,247,585 62,500 0.7581 1.5857 \$38,173,781 \$ 2035 1 187 500 1 250 000 a2 500 ks 0.7750 \$17,678,754 1.5857 \$36,173,781 5 2036 1.187.500 1,250,000 62,500 0.7943 \$18,170,388 1.5857 \$36,272,688 2037 1,187,500 1,250,000 82,500 0.8142 \$18,573,741 1,5857 \$36,173,781 2038 1,187,500 1,250,000 82,500 0.8345 \$19,038,084 1.5857 \$36,173,781 2039 1 187 500 1,250,000 82,500 0.8554 \$19,514,038 1.5657 \$36,173,761 2040 1.187.500 1.250.000 62,500 0.6768 \$20,056 687 5 1.5857 \$36,272,588 2041 1,187,500 1,250,000 62,500 0.8997 \$20,501,934 1 6857 538 173,78 2042 1.187.500 1 250.000 82,500 0.8212 \$21,014,483 1.5857 \$36 173 781 2043 1,187,500 1,250,000 62,500 0.9442 \$21,539,645 1.5857 \$35,173,781 2044 1,187,500 1,250,000 62,500 1.5857 0.9678 \$22,138,829 \$38,272,888 2045 1,187,500 1,250,000 62,500 0,9920 \$22,630,299 1.5857 \$38,173,781 \$ 2046 1 187 500 1 250 000 82 500 1.0168 \$23,198,057 1 5857 \$38,173,781 2047 1 187 500 1.250.000 82,500 1.0422 \$23,775,958 1.5857 \$36,173,781 2048 1.187.500 1,250,000 82,500 1.0683 \$24,437,125 1,5857 \$36,272,688 2049 1,187,500 1,250,000 82,500 1,0950 \$24,979,616 1.5857 \$36,173,781 2050 1,187,500 1,250,000 62,500 1.1224 \$25,604,107 1.5857 \$36 173 781 2051 1,187,500 1,250,000 62,500 1.5857 1,1504 \$28,244,209 \$36,173,781 2052 1,187,500 1,250,000 1,1792 82,500 \$28 974 014 1 5857 \$36,272,888 S 2053 1.187.500 1.250.000 62,500

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 B - FGT Max Rate

Case C - No Value

Case A - Current Market

¹² 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.

1.2087

\$27,572,822

1.5857

\$36, 173, 781

21 Unit refease values based upon FGT Phese VIII Projected Maximum Tartif Recourse Rate as per Exhibit N of FGT's FERC Certificate Filing.

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Attachment V B:

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

		Cost Reco	very for Relaase	Sale of Excess	Capacity Utilizi	ng Various Re	iesse Value Ana	th the section of the section of the section of the section of the section of the section of the section of the	
			1	Case A.C	urrent Marleet	Case 9 - F	OT Kar Bate		
	FPL Natural Gas	Freposed Company R	Capacity	11=1	Revenues		Revenues		Revenues
	Fuel	Delivery	For	Delagra	riom	Unit	from	Unit	from
	Requirements	Canacity V	Beless	Mature 2	CHINNERY	1010030	Capacity	Release	Capacity
Year	(MM Bluiday)	(MMBbe/davi	(MMRhaftavi	Manage -	(Shinese	Values "	Release	Values	Release
Column	1	2		(wawbull	191	(WMBRI)	(\$)	<u>{{\$/MMBtu}</u>	<u>(\$)</u>
			· · · · · · · · · · · · · · · · · · ·			6	7	B	,
_	Attachment VA,	See Footnote		See Fontrate	Col 4 * Col 3 *	See Englande			
Source	Column 1	1/	Col 2 - Col 1	27	date in teas		CDI6-COI3-	Assume No	Col 9 . Col 3 .
Company & Gapacity Project					anyo in year	~ ~	allys in year	Value	daya
Sept 1, 2012 - Dec 1, 2012	- 1	50,000	50,000	\$0.4614	\$2 000 847	5 1 6467		_	
Dec 1. 2012 - Jan 1, 2013	30,000	50,000	20,000	50,4614	\$286.002	1 1 6967	3/,214,935	5	20
Jan 1, 2013 - March 1, 2013	30,000	50,000	20,000	\$0,4614	\$544 498	\$ 14857	84 871 139	3	\$0
March 1, 2013 - Sept 1, 2013	50,000	50,000	0	\$0,4614	so	\$ 15857	80,071,120		54
Sept 1, 2013 - Dec 1, 2013	200,000	400,000	200,090	\$0,4614	\$8,398 187	\$ 15857	500 850 740	:	1 1
Les 1, 2013 - Jan 1, 2014	230,000	400,000	170,000	\$0,4614	\$2,431,783	\$ 1.5857	\$8 358 830		\$4
Manch 1 2014 - March 1, 2014	230,000	400,000	170,000	\$0,4614	\$4,628,231	\$ 1,5857	\$15,904,571	8	34
lune 1 2014 - June 1 2015	250,000	400.000	150,000	\$0,4614	\$6,367,856	\$ 1,5857	\$21 882 660	s	\$40 \$40
2016	400,000	400,000	0	\$0,4614	30	\$ 1,5857	50	8	
2016	400,000	400,000	•	s	SO	\$ 1.5857	50	s	
2010	400,000	400,000	-	5	\$0	\$ 1,5857	50	5	40
2018	400,000	400,000	-	\$	\$0	\$ 1,5857	50	8	
2019	400,000	400,000	-	\$	\$0	\$ 1,6857	\$0	ŝ	30
2020	400,000	400,000	-	\$	\$0	\$ 1,5857	\$0	\$	50
2021	487,600	400,000	-	\$	\$0	\$ 1,5857 [\$0	8	20
2022	575 000	400,000	-	3	\$0	\$ 1.5657	\$0	\$	50
2023	750,000	400,000	-	s i	\$0	\$ 1.5857	\$0	\$	50
2024	837.500	\$27,500	-	1	\$C	\$ 1,5857	\$0	\$	\$0
2025	1.012.500	1 012 600 2	-	:	\$0	\$ 1.5857	\$0	\$	\$0
2026	1,187,500	1 187 500	-	:	şc	\$ 1,5857	\$0	\$	\$0
2027	1,187,500	1,187,500		2	\$C	\$ 1.5857	\$0	\$	\$0
2028	1,187,500	1,187,500	-	:	50	§ 1,5857	so	8	\$0
2029	1,187,500	1,187,500		:	SU	\$ 1.6857	\$0	\$	\$0
2030	1,187,500	1,187,500		š	50	3 1.5857	\$0	\$	\$0
2031	1,187,500	1,167,500		. I	20	\$ 1.5857	\$0	3	\$0
2032	1,187,500	1,187,500	-	s	10	\$ 1.5857 6 4.6657	\$0	3	\$0
2033	1,187,500	1,187,600	-	š	*0	1.0001	\$0	• •	\$0
2034	1,187,500	1,187,500	-	s	50	8 16657	50	.	\$0
2035	1,187,500	1,187,500		s	50	\$ 1.5057	30		\$0
2036	1,187,500	1,187,500		s	80	\$ 15857	80		\$0
203/	1,187,500	1,187,500		s	50	\$ 1.5857	50		*0
2036	1,167,500	1,187,500		\$ İ	50	\$ 1,5857	e01		30
2035	1,107,500 (1,187,500	-	s	\$0	\$ 1,5857	5	š	\$0 \$0
2041	1,187,500	1,187,500		\$	\$0	\$ 1,5857	50	5	**
2042	1,167,500	1,187,600		\$	\$0	1,5857	so	i l	30 \$0
2043	1,187,000	1,187,500		s	\$0] :	1.5657	50	s l	
2044	1 197 500	1,387,500		5	\$0	6 1.5657	50	\$	90 \$2
2045	1 187 500	1,107,000		S	\$0] :	1.5857	\$0	\$ -	50
2046	1 187 500	1 187 500	-13		\$0 \$	1.5857	\$0 1	s	\$1
2047	1,187,500	1 187 500			\$0 \$	1.5857	\$0 5	5	50
2048	1.187.500	1 187 500	-		\$0] \$	1.5857	\$0.5	\$	\$0
2049	1,187.500	1 187 500	- 13		\$0 \$	1.5857	\$0 :	\$	\$0
2050	1,187,500	1.187.500	-		SO 1	1,5857	\$0 ÷	s :	50
2051	1,187,500	1,187,500	11		50 1	1,5857	\$0 5	3 - 1	\$0
			- 6 3		501	4 5057	- Ioe		
2052	1,187,500	1,167,500				1.0007	20 A	•	\$0

¹¹ Proposed Company B delivery capacity in initial years (2012 through 2021) set as consistent with the proposal front Company B. In all years thereafter, capacity set as equal to FPL protected incremental demand.

²⁹ 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.

³¹ Unit release values based upon FGT Phase VIII Projected Maximum Tariff Recourse Rate as per Exhibit N of FGT's FERC Contificate Filing.

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

	Upstream Pipeline Project / Florida EnergySecure Line Project									Variable Costs of 50 is Current Contracted 507 5									
	Average			ACCI FIGURE EARLY	Value Line Pro	Dr.	mincled	······	Valian	10 00	JALS OF PPI	"s Cument Cor	Traci	Ind FGT	Service "	Economic Disr	atch Saving	s vs. Contract	ed FGT Service
	Unsubscribed		Average	}	Total	1 10	all Drice	Variable	1		1	1			1 Martin Mar		2		
	Capacity	FPL	Load	Average	Capacity	of /	Gasinto	Cost on	FOT)	Brojected			Venacian of	Varietie	Gas Cost	fotal Fotal	Francis
	Not Released	Natural Gas	Factor for	Unutilized	Available for	Ur	ostream	Unetream	Fuel		Internet	Basis to	L IIV	Heaters :	(row) coscon	Service Cost	Savings	Conomic	Economic
	in Secondary	Demand	for new	Subscribed	Economic	Plac	line / FPL	Pipeline (Retention	140	Hub	FOT	1.00	A Lunk y	Dipeline	Savings when	With period	Student	Caspatch
	Market	Served	capacity	Capacity	Dispatch	P	Iceline	FPL Protect	Rate	Co	et of Gas	Zone 3	1.00	COT	System	New Poperate	Sustem	Avaitable	Savings
Year	(MMStu/day)	(MMBtu/day)	(%) 1/	(MMBtulyr) 1/	(MMBKu/yr)	157	MIN Bitu)	(S/MMBtul	1963	1180	HARPEN 2	AND BELLEVILLE	100		(CONSTRUCTION)	Systems (CANADDA)	System:	AVAILED IS	Avanable
Column	1	2	3	4	6	+	6	7	6	1.000	9	10	<u> 141-</u>	44	(3////004)		(3/mm/0/u) 44	15	[> 16
						t	<u> </u>		FGT Phase	+		<u>_</u>	 	<u> </u>	1001177			1>	
	lass is some	FPL Base	1.	Col 2 " days in	(Col 1 * days in	Attac	shment IV, [†]	Attachment	VIII Filing -	See	Footnote	See Footnote	Col	9 + Col	Col 8)] - Col	1	Col 11 -	Cel 13 +	
Source	Attachment VB	Resource Plan	See Footnote 1/	year * (1 - Col 3)	year) + Col 4	C	Jol 12	IV, Col 17	Exhibit N		2	3/		10	11	Col 12 - Col 7	Col 6	Col 14	Col 5 * Col 15
2014	1 1	400,000	59%	80,577,700	60,577,700	5	8,7449	\$ 0.2443	3.26%	\$	8,692	\$ 0,0968	\$	8,789	S 0,2962	\$0,0519	\$ 0,0443	0.0902	\$ 5,828,278
2010	. /	400,000	72%	41,242,200	41,242,200	\$	9.2445	\$ 0.2571	3.26%	\$	9.192	\$ 0,0966	\$	9.289	S 0.3130	\$0.0559	\$ 0.0443	0,1002	S 4,133,139
2010	. J	400,000	78%	35,286,000	35,286,000	\$	9.7440	\$ 0.2700	3.26%	S	9.692	\$ 0,0968	\$	9.788	5 0.3299	\$0.0599	\$ 0.0443	0.1042	\$ 3,676,767
2017	, I	400,000	78%	31,997,700 /	31,997,700	\$	10,3435	\$ 0,2852	3,26%	\$	10.291	\$ 0,0968	5	10,368	(S 0.3501	\$0,0848	\$ 0.0443	0,1091	5 3,492,079
2010	, I	400,000	79%	30,513,700	30,513,700	S	11.1428	\$ 0,3053	3.26%	\$	11.090	\$ 0,0968	\$	11.187	S 0.3770	\$0,0717	\$ 0.0443	0,1160	\$ 3,539,604
2020		400,000	78%	31,584,600	31,584,600	s	12.1420	\$ 0.3302	3.26%	\$	12.089	\$ 0.0968	\$	12.165	5 0.4107	\$0.0905	\$ 0.0443	Q.124B	\$ 3,941,567
2021		400,000	76%	34,829,500	34,629,500	5	12,7942	\$ 0,3488	3.28%	\$	12.742	\$ 0,0968	5	12.839	\$ 0.4325	\$0,0859	\$ 0.0443	0,1302	\$ 4.533,935
2022	ļ	40/,000	75%	44,484,3/5	44,484,375	5	13.0490	\$ 0.3539	3.26%	\$	12.997	\$ 0.0968	\$	13.093	S 0.4412	\$0.0873	\$ 0.0443	0.1316	\$ 5,856,337
2023		750,000	75%	52,468,1501	62,468,750	\$	13.3069	\$ 0.3611	3.28%	\$	13.256	\$ 0.0968	\$	13.353	\$ 0.4500	\$0.0868	\$ 0.0443	0.1331	\$ 6,986,102
2024	}	837 500	75%	79 931 360	88,437,500	5	13,5740	\$ 0.4216	3.26%	5	13.522	\$ 0,0968	\$	13.618	\$ 0.4589	\$0,0373	\$ 0.0443	0.0816	\$ 5,583,921
2025	, ,	1 012 500	75%	07 301 635	70,031,290		13.8444	5 0.4494	3.26%	Ş	13,792	\$ 0.0968	\$	13.889	\$ 0,4660	\$0.0186	\$ 0.0443	0.0629	\$ 4,820,803
2026		1 187 500	75%	108 360 375	92,390,025	*	14.1202]	\$ 0,6478	3.20%	S	14.068	\$ 0.0968	\$	14.165	\$ 0.4773	(\$0.0704)	\$ 0.0443		s -
2027		1,187,500	75%	108,359,375	106,359,375		14,4015	\$ 0.0089	3.20%	15	14,349	5 0.0968	5	14.446	\$ 0.4868	(\$0,0721)	\$ 0.0443		s -
2028		1,187,500	75%	108 658 250	108,558,575	e la	14 9810	\$ 0.5703	3.2078	15	74,536	5 0,0508	18	14,733	\$ 0.4965/	(\$0.0738)	\$ 0.0443		s -
2029		1,187,500	75%	108.359.375	108 359 375	ŝ	15 2797	a 0.00181	3.20%	5	14,828	S 0.0906	1S	15.025	\$ 0.5063	(\$0,0755)	\$ 0.0443		\$
2030		1,187,500	75%	108.359.375	108,359 375	\$	15 5842	\$ 0.0007	2.26%	1	10.227	5 0.0800	12	15,324)	\$ 0.51647	(\$0,0773)	\$ 0.0443		s -
2031		1,187,500	75%	108,359,375	108,359,375	ŝ	15.8848	4 06182	3 28%		15,002	a 0,0500	12	10.029	8 0,5207	(\$0.0792)	5 0.0445		5 -
2032		1,187,500	75%	108,656,250	108.656.250	i s	18.2116	9 0.6307	3,26%		18 150	S 0.0968	e le	16 256	8 0.0071	(\$0,0810)	\$ 0.0443		S -
2033		1,187,500	75%	108,359,375	108,359,375	ŝ	16.5348	5 0.6438	3.26%	1	16.482	\$ 0.0968		18 870	e 0.5587	(\$0.0829)	\$ 0.0443 • 0.0443		\$ -
2034		1,187,500	75%	108,359,375	108,359,375	s	16,6644	\$ 0,6567	3,26%	ŝ	18.812	5 0.0965	ŝ	18 909	C 0 5698	(\$0,0645)	# 0.0443		s -
2035		1,187,500	75%	108,359,375	108,359,375	\$	17.2008	\$ 0.6701	3.28%	s	17,148	\$ 0.0968	ŝ	17 245	s 0.5811	(\$0.0005)	E 0.0443		\$
2036		1,187,500	75%	108,658,250	108,656,250	5	17,5436	8 0,6837	3,26%	s	17,491	\$ 0.0968	ŝ	17.588	IS 0.5927	(\$0,0911)	E 0.0443		8 e
2037		1,187,500	75%	108,359,375	108,359,375	\$	17.8933	\$ 0,0977	3,26%	\$	17.841	S 0.0988	s	17,938	5 0.6045	(\$0.0932)	\$ 0.0443		3
2030		1,187,500	75%	108,359,376	108,359,375	\$	18.2501	8 0.7119	3.28%	s	18.198	\$ 0.0968	ls .	16,294	S 0.6165	(\$0,0954)	\$ 0,0443		\$.
2039		1,107,500	75% (108,359,375	108,359,375	\$	18.6140	5 0.7264	3.26%	s	18.561	\$ 0.0968	IS .	18.658	\$ 0.6288	(\$0,0977)	\$ 0.0443		š .
2040		1,167,500	75%	108,856,250	108,656,250	\$	18,9852	\$ 0.7412	3.26%	18	18,933	\$ 0.0968	15	19,029	S 0.6413	(\$0,1000)	\$ 0,0443		s -
2042		1,187,800	/5%	108,359,375	108,359,375	\$	19.3638	\$ 0.7564	3.26%	15	19.311	\$ 0.0968	15	19.408	\$ 0.6540	(\$0,1023)	8 0.0443		s -
2043		1,107,000	75%	108,359,375	108,359,375	5	19.7500	\$ 0.7718	3.26%	5	19,097	\$ 0.0965	5	19.794	\$ 0.6670	(\$0.1047)	\$ 0.0443		s -
2044		1 187 500	75%	108,359,375	108,359,375	15	20.1439	\$ 0,7875	3,26%	5	20.091	\$ 0.0968	s	20.188	\$ 0,6803	(\$0,1072)	\$ 0.0443		s .
2045		1 187 500	75%	108,659,250	108,556,250	5	20.5457	\$ 0.8036	3.26%	5	20,493	\$ 0,0968	5	20.590	\$ 0,6939	(\$0.1097)	\$ 0,0443		5 -
2046		1 187 500	754	108,009,079	108,359,375	15	20.9555	\$ 0.8200	3.26%	5	20.903	\$ 0.0968	\$	21.000	\$ 0.7077	(\$0.1123)	\$ 0.0443		s -
2047		1 187 500	76%	108,359,375	108,309,375	\$	21.3/35	\$ 0.8367	3.26%	1	21,321	\$ 0.0988	\$	21.418	\$ 0.7217	(\$0.1150)	\$ 0.0443		5 -
2048		1,187,500	75%	108,550,570	108,359,3/5	1	21,7999	\$ 0.8536	3.26%	15	21.747	\$ 0,0968	5	21.844	\$ 0.7361	(\$0,1177)	\$ 0.0443		s -
2049		1,187,500	75%	108,050,250	100,000,200	1	22.2.546	\$ 0,8713	3.26%	1	22,162	\$ 0.0968	\$	22.279	\$ 0.7508	(\$0,1205)	\$ 0.0443	•	s -
2050		1,187,500	75%	108 359 375	100,309,319		22.0104	\$ 0.8890	3.26%	5	22.628	\$ 0.0968	Ş	22.723	\$ 0.7657	(\$0.1233)	\$ 0.0443		s -
2051		1,187,500	75%	108 359 375	100,300,375	e	23, 1306	\$ 0,30127	3,20%	1	23,075	\$ 0,0968	5	23.175	\$ 0,7810	(\$0,1262)	\$ 0.0443		5 -
2052		1,187,500	75%	108 656 250	108,658,260	å	24.0624	\$ 0,9251	3.2076	12	23.540	\$ 0.0966	s	23.637	\$ 0,7965	(\$0,1292)	\$ 0.0443		\$ -
2053		1,187,500	75%	108,359,375	108 359 375	ŝ	24.0001	\$ 0.9440	3.2070		24.011	\$ D.0966	\$	24.107	5 0.8124	(\$0,1323)	\$ 0.0443		\$ ^
		the second second second second second second second second second second second second second second second s					61.4 144	4 0.0000 p	4 9,2970 ;	17	24.491	\$ 0,0000	15	24,566 (\$ 0,82667	(\$0,1354)	\$ 0.0443		S .!

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,

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

		Variable Costs of FPL's Current Contracted FGT Service														
	Average					Projected	T	Tanapa Costa or PE & Current Contracted FG (Service -					Economic Dispatch Bavings vs. Contracted FGT Service			
	Unsubscribed		Average		Total	Unit Price	Variable					Variable	U-2-0	.		
	Capacity	FPL	Load	Average	Capacity	of Gas into	Cost on	EGT		Brojecied	Descented	Venables	Vanable	Gas Cost	Total	_
	Not Released	Natural Gas	Factor for	Unutitized	Available for	Upstream	Cinstrant	Funt	Orniontari	Projected Regis in	Projected	(rue) Cost on	Service Cost	Savings	Economic	Economic
	In Secondary	Demand	for new	Subscribed	Economic	Pipeline / FPL	Pipeline /	Retention	Henry Hub	EGT	of Cas inte	FGI	Savings with	with New	Dispatch	Dispatch
	Market	Served	Capacity	Capacity	Dispatch	Pipeäne	FPL Project	Rate	Cost of Gan	7000 2		Pipeline	New Pipeline	Pipeline	Savings	Savings
<u> </u>	(MMBtu/dey)	(MMBtu/day)	(%) 1/	(MMBtu/yr) 1/	(MMBtu/yrt)	(S/MMBtu)	/COMMERCIAL	1963	(ROALDONAL OF	(CALM Day) 20		SAPIRIN .	aystem	System	Available	Available
Column	i	2	3	4	5	6	7		Caranactor 20		(MMMDLU)	[] SAMMETRI	(\$/M/ALBELA)	(SAM MESTA)	(S/MMBtu)	(SfYnar)
1		'				<u>-</u>		FGT Phase		·····	<u> </u>	12	13	<u>14</u>	15	16
Former 1	No Capacity	FPL Base	See	Col 2 " days in	(Col 1 * days in	Attachment IV	Attachment	Vill Filling -	See Footnote	San Ecologia		1000144144	[0.1.44		
300700	rveneased	Resource Plan	Footnote 1/	year * (1 - Col 3)	vear) + Col 4	Col 12	IV, Col 17	Exhibit N	2/	3/	10	Col 33 - Col 11	Cal 12 - Cal 7	Col 11 -	G0E13+	
2014	262,006	400,000	59%	60,577,700	156,209,789	\$ 8,7449	\$ 0.2443	3.26%	\$ 8.692	\$ 0.000p	\$ 1790		COI 12- CUI 7		60114	COL2 . COL 12
2015	198,718	400,000	72%	41,242,200	113,044,289	S 9,2445	\$ 0,2571	3 26%	\$ 9 197	\$ 0.0968	\$ 0,703	¢ 0.2302	\$0.0518	\$ 0.0443	0.0962	5 15,029,194
2010	198,710	400,000	76%	35,286,000	107,284,807	S 9.7440	\$ 0.2700	3.28%	\$ 9,692	\$ 0.0968	\$ 0,203 \$ 0,789	¢ 0.3130	\$0,0009	\$ 0.0443	0.1002	\$ 11,328,875
2017	190,718	400,000	78%	31,997,700	103,799,789	\$ 10.3435	\$ 0.2852	3.26%	\$ 10.291	\$ 0.0988	\$ 10.389	\$ 0.3299	\$0.0599	5 0,0443	0,1042	\$ 11,1/8,9/3
2010	190,718	400,000	79%	30,513,700	102,315,789	\$ 11.1428	\$ 0.3053	3,26%	\$ 11,090	\$ 0.0968	\$ 11187	\$ 0.3301	50.0040	5 0.0443	0.1091	\$ 17,328,223
2020	190,710	400,000	78%	31,584,600	103,386,689	\$ 12.1420	\$ 0.3302	3,26%	\$ 12,089	\$ 0.0966	\$ 17 198	S 0.4107	50.000	8 0.0443	0.1100	\$ 11,868,081
2024	100.210	400,000	76%	34,629,500	106,828,307	\$ 12,7942	\$ 0.3498	3.28%	\$ 12,742	\$ 0.0968	\$ 12,839	8 0.4336	50,0000	5 0.0443	0,1240	5 12,802,034
2022	24 740	487.500	75%	44,484,275	84,348,984	\$ 13.0490	\$ 0.3539	3.26%	5 12.997	\$ 0.0966	\$ 13.093	5 04417	\$0.0009	5 0.0443	0.1302	\$ 13,906,389
2023	50,000	5/5,000	75%	52,468,750	60,395,839	\$ 13,3089	\$ 0.3611	3.26%	S 13,256	S 0.0988	\$ 13.353	5 0.4500	\$0.0899	\$ 0.0443	0,1310	5 13,304,481
2024	162 500	100,000	75%	68,437,500	66,687,500	\$ 13,5740	\$ 0.4216	3,28%	\$ 13.522	\$ 0.0988	\$ 13.818	\$ 0.4589	\$0.0373	5 0.0442	0.1331	\$ 5,941,077
2025	237 500	1 012 500	75%	/6,631,250	136,106,250	\$ 13.8444	\$ 0.4494	3.26%	\$ 13.792	\$ 0,0988	\$ 13.889	\$ 0.4880	50.0186	\$ 0.0443	0.0010	\$ 1.0/2,900 \$ 0.662,722
2026	82 500	1 187 500	7376	92,390,625	179,078,125	\$ 14.1202	\$ 0.5478	3,26%	\$ 14.068	\$ 0.0968	\$ 14,165	\$ 0,4773	(\$0,0704)	\$ 0.0443	0.0020	\$ 0.007.022
2027	82 500	1 197 500	75%	106,359,375	131,171,875	\$ 14.4015	\$ 0,5589	3,26%	\$ 14,349	\$ 0,0968	\$ 14,446	\$ 0.4568	(\$0.0721)	5 0.0443		
2028	62,500	1 187 500	7376	108,359,375	131,171,875	S 14.6885	\$ 0.5703	3.26%	\$ 14.636	\$ 0.0968	\$ 14.733	S 0.4965	(\$6.0738)	5 0.0443		έ.
2029	62,500	1 197 500	75%	100,000,200	131,531,250	\$ 14.9812	\$ 0,5819	3.26%	\$ 14.929	S 0,0988	\$ 15.025	\$ 0.5063	(\$0.0755)	\$ 0.0443		
2030	82,500	1 187 500	754	108,339,375	131,1/1,8/5	\$ 15.2797	\$ 0,5937	3.26%	\$ 15.227	S 0.0966	\$ 15,324	S 0.5164	(\$0.0773)	\$ 0.0443		š
2031	82,500	1 187 500	754	109,309,375	131.1/1,8/6	\$ 15.5842	\$ 0.6058	3.25%	\$ 15.532	S 0.0968	\$ 15.629	\$ 0.5287	(\$0,0792)	\$ 0.0443		5 -
2032	62,500	1,187,500	75%	108,658,370	131,1/1,8/5	\$ 15,8948	\$ 0.6182	3.26%	\$ 15.842	\$ 0.0968	\$ 15,939	\$ 0.5371	(\$0,0810)	\$ 0.0443		s .
2033	62,500	1,187,500	75%	108 359 376	131,031,200	\$ 16.2116	\$ 0,6307	3,26%	\$ 16.159	\$ 0.096a	\$ 16.258	\$ 0,5478	(\$0.0829)	\$ 0.0443		s -1
2034	62,500	1,187,500	75%	108 359 375	131,171,075	\$ 10,0348 5 40,0044	\$ 0.6438	3.26%	\$ 16,452	\$ 0.0988	\$ 16.579	\$ 0.5587	(\$0.0849)	\$ 0.0443		\$.
2035	62,500	1,187,500	75%	108 359 375	131 171 975	5 10,0044	\$ 0.0007	3.26%	\$ 16.812	\$ 0.0968	\$ 16.90S	\$ 0.5698	(\$0.0869)	\$ 0.0443		s -
2036	62,500	1,187,500	75%	108 656 250	131 531 250	# 17.2000 8 17.5405	\$ U,D/U1	3.26%	\$ 17.148	\$ 0,0968	\$ 17.245	\$ 0.5811	(\$0.0890)	\$ 0,0443		s -
2037	62,500	1,187,500	75%	108.359.375	131 171 675	tr.3433 tr.343 tr.	5 0.063/	3.26%	\$ 17.491	\$ 0.0958	\$ 17,588	\$ 0.5927	(\$0.0911)	\$ 0.6443		5 -
2038	62,500	1,187,500	75%	108,359,375	131 171 875	\$ 18,2504	\$ 0.08// \$ 0.7110	3.20%	\$ 17.841	\$ 0.0968	\$ 17.938	\$ 0.6045	(\$0.0932)	\$ 0.0443		s -
2039	62,500	1,187,500	75%	108,359,375	131.171.875	\$ 18 5140	5 0.7784	3,20%	\$ 16,198	\$ 0,0968	\$ 18.294	\$ 0.6165	(\$0.0954)	\$ 0,0443		\$ -
2040	62,500	1,187,500	75%	108,658,250	131,531,250	\$ 18,9852	5 0.7412	3.2079	\$ 16,501 \$ 46,020	\$ 0.0968	\$ 18,658	\$ 0.6288	(\$0.0977)	S 0.0443		\$-
2041	62,500	1,187,500	75%	108,359,375	131.171.875	\$ 193638	5 0.7584	3,2076	8 10.803	\$ 0.0968	\$ 19.029	\$ 0.6413	(\$0.1000)	\$ 0.0443		\$ -
2042	62,500	1,187,500	75%	109,359,375	131,171,875	\$ 19,7500	\$ 0.7718	8 26%	5 18,311 E 10,002	S 0.0968	\$ 19,408	\$ 0.6540	(\$0.1023)	\$ 0,0443		\$ -
2043	62,500	1,187,500	75%	108,359,375	131,171,875	\$ 20,1439	\$ 0.7875	1 2894	5 10.097 6 20.001	5 0.0000	\$ 19./84	\$ 0.6670	(\$0,1047)	\$ 0.0443		s -
2044	62,500	1,187.500	75%	108,656,250	131,531,250	\$ 20,5457	\$ 0,8038	3 28%	5 20,051	\$ 0.0908	\$ 20,188	\$ 0.6603	(\$0.1072)	\$ 0.0443		\$-
2045	62,500	1,187,500 }	75%	108,359,375	131,171,875	\$ 20,9555	\$ 0.8200	3 26%	\$ 20,000	5 0.000s	\$ 20.590	5 0.6939	(\$0,1097)	5 0.0443		s -
2040	62,500	1,187,600	75%	108,359,375	131,171,875	\$ 21.3735	5 0.8387	3.26%	5 21.303 5 21.321	s 0,0908	5 21.000	S 0,7077	(\$0,1123)	\$ 0.0443		s -
204/	62,500	1,187,500	75%	108,359,375	131,171,875	\$ 21.7999	\$ 0.853B	3,26%	5 21.747	\$ 0.09901	♥ 61.418 € 24 844	0.7217	(\$0.1150)	5 0.0443		\$ -
2040	62,500	1,187,500	75%	108,656,250	131,531,250	\$ 22.2348	\$ 0.8713	3,26%	\$ 22,182	\$ 0.090+	5 22 270	s 0.7367	(30.1177)	5 0.0443		s -
2050	62,500	1,187,500	75%	108,359,375	131,171,875	\$ 22.6784	\$ 0.8890	3.26%	\$ 22,828	\$ 0,0008	\$ 22,729	0,7508	(\$0,1205)	5 0.0443		s -
2051	62,500	1,187,500	75%	108,359,375	131.171,875	\$ 23,1308	\$ 0.9072	3.26%	\$ 23.078	\$ 0.0964	5 23 174	0,705/	(30.1233)	a 0.0443		s -1
2052	62,500	1,187,500	75%	108,359,375	131,171,875	\$ 23,5923	\$ 0.9257	3.26%	\$ 23.540	\$ 0.0964	\$ 23,637	s 0.7010	(\$0.1262)	ə U.U443		s -
2053	62,500	1,107,500	75%	108,656,250	131,531,250	\$ 24.0631	\$ 0.9448	3.26%	\$ 24,011	\$ 0.098A	\$ 24 107	\$ 0,8124	(30, 1292)	0.0443		s -)
	02,000	5, 107, 000 j	/370	108,358,375	131,171,875	\$ 24.5432	\$ 0.9639	3.26%	\$ 24,491	\$ 0.098a i	\$ 24.58R	S 0.87ea	(\$0.1323)	5 0.0445 5 0.0445		s -
-								_				- <u>0.04</u> 00		0 0,0440		ə •

1/ Cepecity 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 sarve Wire that he ye quelieses on mining exponents reporting to the sine of the calculater. It is not to a report of a registric strategy quelies to a registric strategy quelies and the source of the source of the source of the proposed project capacity and the FGT capacity under contract.



Docket No. 090172-EI Capacity Holders on Pipelines Upstream of Transco Station 85 Exhibit TCS-10, Page 1 of 1

Guif 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	

Docket No. 090172-EI Marginal Cost to Transport to Transco Station 85 Exhibit TCS-11, Page 1 of 1

Marginal Cost to Transport Supplies from Perryville to Transco Station 85

sumed Value of Compressor Fuel Gas at Perryville (average 2014 price per FPL forecast)	\$8.69 p	oer MMBtu	
ute 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	<u>\$0.0013</u>	<u>\$0.0013</u>
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
		60.0122	ćo 0422

Route 2 - Gulf South (East TX to Mississippi 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	<u>\$0.0064</u>
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	<u>\$0.0086</u>	<u>\$0.0086</u>
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

Marginal transport cost to transport supplies to Station 85 vs. to Perryville	\$0.0518	\$0.0518
Total Variable Cost via Gulf Crossing to Perryville	\$0.1433	\$0.1433
Incremental Commodity Rate for service on Southeast Expansion Capacity Lease 0.0046	<u>\$0.0046</u>	<u>\$0.0046</u>
Incremental Fuel Retention Rate for service on Southeast Expansion Capacity Lease 0.54%	\$0.0472	\$0.0472
Gulf Crossing Commodity Rate 0.0037	\$0.0037	\$0.0037
Gulf Crossing Fuel and L&U Rate 1.00%	\$0.0878	\$0.0878
Gulf Crossing (Variable Cost to Transport Supplies from Field Points to Transco Station 85)		
Total Variable Cost via Gulf Crossing to Perryville	\$0.0915	\$0.0915
Gulf Crossing Commodity Rate 0.0037	\$0.0037	\$0.0037
Gulf Crossing Fuel and L&U Rate 1.00%	\$0.0878	\$0.0878
Gulf Crossing (Variable Cost to Transport Supplies from Field Points to Perryville)		

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

utheast Supply Header of 1	<u>Southeast Supply Header Customer Listing</u> [Sourced from Neg. Rate Section of SESH Tariff (Tariff Sheets 21 through 21G)]					
r-EI n Sc uge]		Rate	Contract	MDQ		
[72 Pa	Shipper	Schedule	INumber			
2, let 90	EOG RESOURCES, INC.	FIS	84005	50,000		
S-10 0	FLORIDA POWER & LIGHT CO	FTS	84001	400,000		
jó Ħ́ Ŭ́	FLORIDA POWER & LIGHT CO	FTS	84002	100,000		
2 & E	FLORIDA POWER CORPORATION D/B/A PROGRESS ENERGY FLORIDA	FTS	84006	150,000		
bi g	FLORIDA POWER CORPORATION D/B/A PROGRESS ENERGY FLORIDA	FTS	84007	50,000		
E B	SOUTHERN COMPANY SERVICES INC	FTS	84004	175,000		
ရိပ်ရိ	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		

Docket No. 090172-EI Total Cost to Transport from Perryville to FGT Mobile Bay Area Exhibit TCS-13, Page 1 of 1

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

Perryville Basis Range		(\$0.0900)	(\$0.1400)
Cost of Service on SESH		4	
Reservation Charge (Current FPL Negotiated Ra	te)	<u>\$0.2750</u>	<u>\$0.2750</u>
Total Fixed Cost		\$0.2750	\$0.2750
Fuel Rate	0.70%	\$0.0613	\$0.0613
Commodity \$	0.0045	<u>\$0.0045</u>	<u>\$0.0045</u>
Total Marginal Cost		\$0.0658	\$0.0658
Total Cost		\$0.3408	\$0.3408
Value at FGT/Gulfstream (Perryville + Total Cost)		\$0.2508	\$0.2008