BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

DOCKET NO. 09 0172 EI
FLORIDA POWER & LIGHT COMPANY

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

DIRECT TESTIMONY & EXHIBITS OF:

TIMOTHY C. SEXTON

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BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

FLORIDA POWER & LIGHT COMPANY

DIRECT TESTIMONY OF TIMOTHY C. SEXTON

DOCKET NO. 09_____-EI

Q. Please state your name, position and business address.

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

Q. On whose behalf are you testifying in this proceeding?

A. I am testifying on behalf of Florida Power & Light Company (FPL).

Q. Please describe your education, background and qualifications.

A. I received a Bachelor of Science degree in Civil Engineering from the University of Texas in May 1989 and a Masters in Business Administration from the University of Houston in August 1993. I am also a licensed professional engineer in the state of Texas. I have been with Gas Supply Consulting, Inc. since June 1994. Prior to that, I was employed by Koch Gateway Pipeline Company (formerly United Gas Pipeline Company and currently Gulf South Pipeline Company) in various engineering, operations, planning and marketing positions culminating in the position of Regional Manager of Supply Services. At Gas Supply Consulting, Inc., I perform various consulting functions on behalf of client companies. Some of the functions that I performed over the past several years have included:

(a) evaluated local natural gas supply and pipeline infrastructure to assess ability of such infrastructure to receive large quantities of natural gas from proposed liquefied natural gas (LNG) facilities in various states; (b) evaluated large scale greenfield pipeline project infrastructure alternatives on behalf of utility clients in Wisconsin; (c) represented client interests in negotiations with interstate pipeline companies upstream and/or downstream of client facilities; (d) acted as a technical representative in evaluating regulatory filings; and (e) evaluated pipeline expansion projects and conducted feasibility studies of such projects.

With respect to the Florida marketplace, I have performed numerous functions on behalf of FPL on various assignments since 1998. These assignments generally focused on assessment of the Florida pipeline infrastructure and its ability to meet the needs of FPL generation expansions at various proposed locations. I have also been engaged by the Florida Reliability Coordinating Council (FRCC) since 2005 to evaluate the reliability of the fuel supply infrastructure serving the state of Florida. Finally, I have directed the development of natural gas supply and capacity portfolios on behalf of two industrial clients with facilities in the state of Florida.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to (i) review the need for incremental pipeline capacity to serve future power generation fuel requirements of FPL; (ii) evaluate the capacity solicitation process undertaken by FPL to assess alternatives in meeting incremental natural gas pipeline capacity demand; (iii) compare the benefits provided by the proposed Florida EnergySecure Line versus other alternatives available to FPL; and (iv) evaluate FPL's conclusion that the best means of providing the needed incremental new transportation capacity required to meet forecasted natural gas fired generation requirements in 2014 and beyond is the Florida EnergySecure Line.

Q. Are you sponsoring any exhibits in this proceeding?

A. I am sponsoring the following exhibits which are attached to my direct testimony:

- TCS-1 Resume of Timothy C. Sexton
- TCS-2 Florida Pipeline Capacity Load Factor Calculation
- TCS-3 Schematic Illustration entitled, "Capacity to Southeast Markets"
- TCS-4 Chart of Projected Capacity Upstream of Transco CS 85
- TCS-5 State by State Comparison of Consumption of Natural Gas for Electric Generation in the United States
- TCS-6 Approximate Cost of Service to Transport Natural Gas from Transco CS 85 to Company B Project (Confidential)
- TCS-7 Gas Cost Savings Analysis (Confidential)

Q. Please summarize your testimony.

A. My testimony examines the current natural gas supply alternatives available to FPL including (i) the existing pipeline infrastructure in the state of Florida; (ii) gas supply access available to the state via this infrastructure; and (iii) the need for new natural gas pipeline capacity into Florida to meet demand requirements of FPL and third party markets.

In addition, with respect to potential future natural gas supply access, my testimony (i) summarizes the proposed Florida EnergySecure Line project; (ii) reviews FPL's Solicitation process utilized to assess alternative means available to obtain needed incremental pipeline capacity; (iii) examines FPL's evaluation of proposals received from various bidders into the Solicitation; and (d) develops a comparative economic analysis of the FPL-sponsored project versus alternative proposals received in the Solicitation process.

Based upon the review of these subjects, my testimony concludes:

(a) The existing pipeline infrastructure does not provide sufficient excess capacity to meet FPL's projected future natural gas requirements;

(b) New pipeline infrastructure will need to be constructed to meet the future natural gas demand of FPL as well as third party consumers in Florida;

(c) FPL would be well served to expand natural gas supply access beyond its current concentration from traditional onshore Gulf Coast and offshore Gulf of Mexico sources;

(d) The Solicitation process utilized by FPL was an effective method of analyzing pipeline alternatives available to meet FPL future natural gas demand requirements;

(e) FPL evaluated the various proposals received in response to its Solicitation process in an objective and fair manner; and

(f) FPL has made the correct choice in determining that the Florida EnergySecure Line project is the best option to add needed natural gas pipeline infrastructure to meet the needs of FPL's customers.

Q. Please describe FPL's proposed pipeline project.

A. FPL's pipeline project (the "Project") consists of (i) a pipeline project to be developed by a pipeline operator active in the southeastern United States (Company E) to transport 600,000 Million Btu per day (MMBtu/day) (approximately 600 MMcf/day) of natural gas from a point near Transcontinental Gas Pipeline Company LLC's (Transco) Compressor Station 85 (Transco Station 85) in Choctaw County, Alabama to a point near Florida Gas Transmission, LLC's (FGT) Compressor Station 16 (FGT Station 16) in Bradford County, Florida (the "Upstream Pipeline Project"); and (ii) construction of a new FPL owned and operated intrastate pipeline (the "Florida EnergySecure Line") consisting of approximately 280 miles of 30-inch pipeline from an interconnection with the proposed Upstream Pipeline Project in Bradford County, Florida to a delivery point at FPL's existing Martin generation plants. In addition, the project also includes connections to FPL's modernized Cape Canaveral Next Generation Clean Energy Center

(CCEC) and Riviera Beach Next Generation Clean Energy Center (RBEC) facilities (Modernization Projects) via lateral line extensions. The Florida EnergySecure Line has a proposed in-service date of January 2014.

The Project will initially provide an incremental 600 million cubic feet per day (MMcf/day) of natural gas transportation capacity into the state of Florida which can be expanded to in excess of 1.2 billion cubic feet per day (Bcf/day) via compression additions. The Project will initially support the natural gas fuel requirements of FPL's Modernization Projects recently approved by the Florida Public Service Commission (FPSC).

EXISTING NATURAL GAS PIPELINE INFRASTRUCTURE IN FLORIDA

Q. Please identify pipelines that deliver natural gas into the state of Florida.

A. Currently, natural gas supplies are delivered into the state of Florida by four interstate pipeline systems. These pipelines include FGT, Gulfstream Natural Gas System L.L.C. (Gulfstream), Southern Natural Gas Company's Cypress Pipeline system (Cypress) and Gulf South Pipeline Company, L.P. (Gulf South). With this said, Cypress has direct deliveries only to markets in the Jacksonville area and Gulf South provides direct deliveries only to markets in the Pensacola area. FGT and Gulfstream, on the other hand operate pipeline systems that extend into various markets within the state of Florida and provide approximately 90% of the gas transportation capacity available into the state.

Q. Please provide a brief overview of natural gas transportation capacity into Florida via the Gulfstream and FGT systems.

A. FGT has the capacity to transport approximately 2.21 Bcf/day into Florida and Gulfstream, with the recent installation of its Phases III and IV projects, now has the capacity to transport about 1.25 Bcf/day into Florida. Consequently, the total transportation capacity into Florida via these two pipelines is about 3.5 Bcf/day. In addition, FGT has recently made a Certificate Filing with FERC to initiate its Phase VIII expansion project which would serve to expand its capacity into Florida markets by an incremental 820,000 MMBtu/day (approximately 820 MMcf/day) with a proposed in-service date of April 1, 2011. Thus, after installation of FGT's Phase VIII expansion project, total pipeline capacity into the state from these two pipelines will be approximately 4.3 Bcf/day.

Q. Please provide a description of the Florida Gas Transmission system.

A. FGT's system extends from South Texas through Texas, Louisiana, Mississippi and Alabama to its Florida markets. The system is designed to gather natural gas at supply area interconnects within its Western Division upstream of the Florida/Alabama state line (supplies received in Texas, Louisiana, Mississippi and Alabama) for delivery to markets within its Market Area in the state of Florida. As stated above, FGT's pipeline system currently has the capacity to transport about 2.2 Bcf/day of gas supplies into Florida from Western Division receipt points.

Q. Does FGT have any pending expansion projects?

A. Yes. FGT has recently filed in FERC Docket Number CP09-17-000 to expand its system by 820,000 MMBtu/day (about 820 MMcf/day). This project is FGT's Phase VIII Expansion Project. After installation of Phase VIII facilities, FGT will maintain in excess of 3 Bcf/day of pipeline capacity into the state of Florida.

Q. Please describe FGT's filed Phase VIII expansion project.

A. The project consists of the installation of expansion facilities necessary to enable FGT to receive incremental supplies from interconnects in the Mobile Bay Area and transport these quantities to various delivery locations within the state of Florida.

Per FGT's filing, the Phase VIII project consists of the installation of "(i) approximately 357.3 miles of new pipeline looping on its existing mainline system, (ii) approximately 89.8 miles of new interstate natural gas pipeline, (iii) two customer laterals totaling approximately 36.1 miles, (iv) 213,600 horsepower of additional mainline compression at eight existing compressor stations and one new compressor station, (v) various new and upgraded meter stations, and (vi) ancillary facilities." In addition, FGT is seeking approval to acquire FPL's Martin Lateral and to operate this facility to provide service in conjunction with the proposed expansion project. Finally, the project also includes a requested authorization by FGT to "increase the maximum allowable operating pressure of previously certificated facilities". FGT also notes in its filing that if its request to increase the maximum allowable operating pressure of its existing facilities is denied, then the project will require an additional 80.5 miles of 36-inch pipeline looping along its existing mainline.

Q. Please provide a description of the Gulfstream system.

A. Gulfstream's system is designed to gather natural gas from various receipt points in the Mobile Bay Area to its mainline Compressor Station near Coden, Alabama. The system then extends from the Coden Compressor Station across the Gulf of Mexico to an onshore landing in the state of Florida near Manatee, Florida. Gulfstream then extends from its onshore landing to various delivery points in Florida and terminates at its delivery point to FPL's West County Energy Center in Palm Beach County, Florida. With its Phases III and IV expansion projects now in service, Gulfstream has a design capacity of approximately 1.25 Bcf/day into Florida.

Q. Please summarize FPL's contractual firm transportation capacity rights on FGT and Gulfstream.

A. As discussed in the testimony of FPL witness Sharra, FPL currently has 874,000 MMBtu/day (approximately 874 MMcf/day) of firm transportation capacity on the FGT system which will expand to a total of 1,274,000 MMBtu/day (approximately 1.27 Bcf/day) after FGT's Phase VIII expansion project is in service; and has a total of about 535,000 MMBtu/day (approximately 535 MMcf/day) on Gulfstream which will rise to 695,000 MMBtu/day (approximately 695 MMcf/day) as of June 1, 2009.

Q. **Does FPL hold firm transportation capacity on Gulf South or Cypress?**

No. As the Gulf South and Cypress systems are not configured to provide deliveries directly to FPL markets in the state of Florida, FPL has no firm transportation capacity on either Cypress or Gulf South.

Q. **Is firm interstate capacity in Florida constrained today?**

A. Yes. Despite the introduction of incremental capacity via Gulfstream's recent Phases III and IV expansion projects as well as the introduction of incremental capacity via the construction of the Cypress Project (Phase I was placed in service in May 2007 and Phase II was placed in service in May 2008), interstate transportation capacity in Florida is still effectively sold out and therefore constrained on a firm contractual basis.

Q. **Is a large portion of the firm capacity into the state of Florida underutilized and available for sale in the secondary market under non-peak day conditions?**

A. No. The Florida market, dominated by gas consumption in support of electric generation, is a high load factor market. In fact, based upon data compiled by the Energy Information Administration (EIA) of the United States Department of Energy (DOE) over the twelve month period of December 2007 through November 2008 (the most recent 12 month period for which EIA data is available) more than 85% of total gas consumption in Florida was to support electric generation. Total natural gas demand in the state of Florida for the twelve month period of December 2007 through November 2008 was about 939 Bcf and natural gas demand to support electric generation during this period was about 801 Bcf or approximately 85% of total demand. As depicted in the table attached as Exhibit TCS-2, a comparison of natural gas consumption versus capacity into the state reveals that capacity into the state was utilized at an annual average load factor of nearly 70% of design pipeline capacity during this period. Further, during the peak summer months of June through September, capacity into the state was utilized at an approximate average load factor of almost 80% of available design capacity.

Perhaps most importantly, under peak demand conditions, when capacity is most needed, the pipelines into the state operate at or near capacity. As an example, per FGT's "Operationally Available Capacity" posting on its Electronic Bulletin Board, on August 6 and 7 of 2008, FGT's system through its Compressor Station 12 operated at levels in excess of 96% of design capacity.

As per the provisions of its FERC Gas Tariff, one tool that FGT has to manage its pipeline system is the right to issue Alert Day Notices. Section 13.D.2 of FGT's Tariff states that "Alert Day notices may be issued by Transporter when in its sole discretion, reasonably exercised, Transporter determines that the pipeline is experiencing or may experience in the next gas day high or low line pack operating conditions which threaten the ability to render firm services." As further evidence of the high capacity utilization on the FGT system, FGT issued approximately one hundred Alert Day Notices over the past year and during the peak summer season of June through September of 2008, FGT issued a total of sixty Alert Day Notices.

Q. **In summary, is there capacity available via the existing natural gas pipeline infrastructure in Florida to support incremental firm natural gas demand?**

A. As detailed above, the existing infrastructure is fully subscribed on a long-term firm contractual basis and there is currently no existing pipeline capacity available in the state to be contracted on a long-term firm basis. Further, per FGT's Phase VIII expansion filing, FGT has executed precedent agreements with shippers accounting for fully 731,000 MMBtu/day of the 820,000 MMBtu/day of Phase VIII expansion capacity. Thus, only 89,000 MMBtu/day (approximately 89 MMcf/day) of this Phase VIII expansion capacity is unsubscribed and available. To summarize, absent the introduction of incremental pipeline capacity, the existing natural gas pipeline infrastructure cannot support incremental firm natural gas demand and if FGT's Phase VIII project is considered, only 89,000 MMBtu/day of capacity will be available after installation of Phase VIII facilities to support incremental firm natural gas demand.

NATURAL GAS SUPPLY MIX

AVAILABLE TO FLORIDA CONSUMERS

Q. Please provide a description of the natural gas supply mix accessible via FGT.

A. Within its Western Division, the portion of its system upstream of Compressor Station 10 in Perry County, Mississippi, FGT serves to gather gas supplies from traditional onshore Gulf Coast and offshore Gulf of Mexico sources and has a design capacity to gather and transport about 1.33 Bcf/day of gas supplies. Thus, in order to transport its design capacity into Florida, the remainder of gas supplies, about 880 MMcf/day, must be received into FGT between its Compressor Station 10 and the Florida border in and around the Mobile Bay Area.

In addition, FGT's Phase VIII expansion project does not include any facility expansions upstream of the Mobile Bay Area. As such, after its Phase VIII expansion is placed into service in 2011, FGT required receipts from the Mobile Bay Area under design day conditions will total about 1.7 Bcf/day. These Mobile Bay Area receipts consist primarily of (i) traditional Mobile Bay supplies, (ii) offshore Gulf of Mexico supplies received via the Destin Pipeline Company system; and (iii) receipts from the recently constructed Southeast Supply Header (SESH) system.

Q. Please provide a description of the gas supply mix accessible via Gulfstream.

A. Gulfstream receives 100% of the gas supply into its system from pipeline interconnection points in and around the Mobile Bay Area. Thus, the full 1.25 Bcf/day of supply required into Gulfstream under design day conditions currently must be received into Gulfstream from (i) traditional Mobile Bay area supplies, (ii) offshore Gulf of Mexico supplies received via the Destin Pipeline Company system; and (iii) receipts from the recently constructed SESH system.

Q. In summary, what is the overall supply mix available to the Florida market via FGT and Gulfstream?

A. As discussed above, after installation of its Phase VIII facilities, FGT will provide access to receipts into its system of approximately 1.33 Bcf/day of traditional onshore Gulf Coast and offshore Gulf of Mexico supply sources and 1.70 Bcf/day of receipts into its system in and around the Mobile Bay Area and Gulfstream has its entire 1.25 Bcf/day of receipt capacity in and around the Mobile Bay Area. In summary, after the installation of FGT's Phase VIII expansion project, these two pipelines will provide the Florida market with access to 1.33 Bcf/day of traditional Gulf of Mexico supply sources and 2.95 Bcf/day of receipts in and around the Mobile Bay Area.

Q. More specifically, please summarize FPL's current supply access rights on Gulfstream and FGT.

A. After initiation of service under FGT's Phase VIII expansion project, FPL's primary receipt point rights on FGT will include 680,000 MMBtu/day (approximately 680 MMcf/day) of receipts from points in and around the Mobile Bay Area and 594,000 MMBtu/day (approximately 594 MMcf/day) of receipts from traditional Gulf of Mexico supply locations. Further, FPL's primary receipt point rights on Gulfstream will include 695,000 MMBtu/day (approximately 695 MMcf/day) of receipts from Mobile Bay Area points. In total, FPL will have firm access to about 1.4 Bcf/day of Mobile Bay Area supply and about 0.6 Bcf/day of traditional Gulf Coast / Gulf of Mexico supply.

Q. What is the production outlook for traditional onshore Gulf Coast / offshore Gulf of Mexico supplies in the future?

A. Traditional Gulf Coast production can be separated into three distinct categories of production including: (i) onshore Gulf Coast production; (ii) shallow (depth less than 200 meters) offshore Gulf of Mexico production; and (iii) deepwater (depth greater than 200 meters) offshore Gulf of Mexico production. Production in these areas has declined over the past several years and in the future, the EIA estimates production in shallow water and onshore Gulf Coast fields will continue to decline slowly through 2030. More specifically, within its "Annual Energy Outlook 2009," the EIA projects that onshore Gulf Coast production will decline from current (2008) levels of

5.5 Trillion cubic feet (Tcf) to 3.3 Tcf in 2030 and further projects that offshore shallow water production will decline from current levels of 1.7 Tcf in 2008 to 0.9 Tcf in 2030. Meanwhile, EIA further projects that deepwater production will rise from a current 2008 level of 1.4 Tcf up to a peak of 3.1 Tcf in 2025 and then remain at levels between 2.9 and 3.1 Tcf each year through 2030. While the EIA projects that deepwater production will provide somewhat of an offset to declines in onshore Gulf Coast and shallow Gulf of Mexico production, deepwater increases are not projected to fully offset these declines. As such, the aggregate EIA projection for these three sources will steadily decline from current levels of 8.6 Tcf per year to 7.3 Tcf per year in 2030.

Q. Are forecasts for natural gas production in Mobile Bay consistent with Gulf of Mexico forecasts?

A. Yes. EIA Production forecasts for shallow water Gulf of Mexico production includes gas produced in Mobile Bay area fields. In addition, deepwater gas that flows into Mobile Bay area pipelines is included in the deep water Gulf of Mexico production data discussed above. With this said, data specific to Alabama State Offshore production fields indicates a decline in production consistent with that for the overall shallow water Gulf of Mexico production. In fact, according to EIA data, Alabama State Offshore production peaked at a level of 222 Bcf/year in 1998 and has steadily declined since to a level of 134 Bcf/year in 2007.

Q. Are there any unique risks associated with onshore Gulf Coast and offshore Gulf of Mexico production?

A. Yes. Onshore Gulf Coast as well as offshore Gulf of Mexico production facilities are subject to disruption due to hurricane activity in the Gulf of Mexico. As an illustration, in August 2005, within its "Hurricane Katrina Evacuation and Production Shut-In Statistics" report, the Minerals Management Service (MMS) of the United States Department of the Interior (DOI) reported that as Hurricane Katrina passed over the Gulf of Mexico approximately 88% of normal daily Gulf of Mexico natural gas production (about 8.8 Bcf/day out of a total 10 Bcf/day) was shut in. In addition, in the following month, as Hurricane Rita passed over the Gulf of Mexico, the MMS reported that approximately 80% of normal daily gas production (about 8 Bcf/day out of 10 Bcf/day) was shut in. Finally, the MMS reported that over nine months after these two hurricanes had passed by, in June 2006, approximately 11% of offshore Gulf of Mexico production had yet to return online.

It is important to note that hurricane events present a unique risk to Gulf Coast production while hurricanes do not present the same impact further inland.

Q. Please describe supply sources available into Mobile Bay area receipt points on Gulfstream and FGT.

A. Gulfstream and FGT share many of the same supply sources in the Mobile Bay Area. These sources include pipeline interconnects with (a) Transco's

Mobile Bay Lateral and Gulf South Pipeline Company's Mobile Bay Lateral (both of which receive gas supplies from Mobile Bay Production); (b) Destin Pipeline Company which receives gas supplies from offshore Gulf of Mexico southeastern Louisiana Production Fields; and (c) the newly constructed SESH system.

Q. Are you aware of any new supply sources that will be made available to Gulfstream and FGT in the Mobile Bay area in the near future?

A. Yes. Gulf LNG Energy, a subsidiary of the El Paso Corporation is currently constructing an LNG regasification facility in Pascagoula, Mississippi. As per Gulf LNG's website, the Gulf LNG plant has a projected in-service date in 2011 and will have a peak send-out capacity of 1.3 Bcf/day. The project has proposed interconnections directly with Gulfstream as well as with the proposed Pascagoula Expansion Project pipeline to be jointly owned by FGT and Transco. The Pascagoula Expansion Project will receive gas supplies from the Gulf LNG project and will deliver to FGT's proposed Mobile Bay Project, which in turn would provide access to FGT's mainline. As detailed in a the joint Request for Pre-Filing Review filed in FERC Docket PF08-31-000 by Transco and FGT, capacity dedicated to FGT on the Pascagoula Expansion Project is 340,000 MMBtu/day (approximately 340 MMcf/day).

Q. Are there any issues or concerns that need to be considered in evaluating the Gulf LNG facility as a long-term firm gas supply source for FPL?

A. Yes. First, the Gulf LNG facility will be located in Pascagoula, Mississippi on the Gulf Coast. As such, this facility will be subject to the same severe weather conditions during hurricanes that have the potential to impact onshore Gulf Coast and offshore Gulf of Mexico production sources. Further, LNG trades on a worldwide market and will typically be delivered to the highest value market available at any given time. For example, the EIA reported that during 2008 a total of about 352 Bcf of natural gas as LNG was imported into the U.S. This represented about 45% of the total 771 Bcf of LNG that the EIA reported was imported during 2007. This substantial reduction in LNG imports is due to the fact that United States demand for LNG competes with demand in other parts of the world. As a result, if demand is greater (and values are higher) for LNG elsewhere in the world than in the U.S., the LNG will likely flow to the highest value market.

Q. Please provide a description of the Southeast Supply Header and natural gas supplies accessible via the Southeast Supply Header.

A. SESH was placed into service during the fall of 2008 and consists of 274 miles of 42 and 36-inch pipeline extending from the Perryville Hub in Northern Louisiana to its terminus at its interconnection with Gulfstream in Coden, Alabama. The pipeline has a maximum transportation capacity of 1.0 Bcf/day. Approximately 95% of this 1 Bcf/day of pipeline capacity is currently subscribed under long-term firm transportation agreements. As such, while SESH has provided a needed addition of supply diversity to Gulfstream and FGT in the Mobile Bay area, the pipeline, as currently configured, is essentially sold out and unavailable to provide incremental supply to the Florida market.

Q. Does FPL have any contracted capacity on SESH?

A. Yes. FPL has a long-term contract for 500,000 MMBtu/day (approximately 500 MMcf/day) of capacity on SESH from the Perryville Hub to Gulfstream and FGT in the Mobile Bay area.

Q. Taking into account FPL's capacity on SESH, please summarize natural gas supply access available to FPL via its connected pipelines.

A. As stated previously in my testimony, after initiation of service under FGT's Phase VIII expansion project, FPL's primary receipt point rights on FGT and Gulfstream will provide access to about 1.4 Bcf/day of Mobile Bay Area receipts and 0.6 Bcf/day of traditional onshore and offshore Gulf of Mexico Area receipts. With SESH capacity providing access to Perryville Hub supplies, FPL's supply mix consists of about (a) 0.5 Bcf/day available from the Perryville Hub via SESH or directly from Mobile Bay Area supply points; (b) 0.9 Bcf/day from non-SESH Mobile Bay Area receipts; and (c) 0.6 Bcf/day of traditional Gulf Coast receipts.

Q. Please provide a description of natural gas available at the Perryville Hub.

A. In addition to receiving traditional Gulf of Mexico production, via upstream connected pipelines the Perryville Hub also receives supplies of natural gas from the Barnett Shale in Texas, the Haynesville Shale in North Louisiana, the Woodford Shale in Southeastern Oklahoma and the Fayetteville Shale in Northeast Arkansas.

Q. Other than SESH, are there any other pipeline projects under development that have the potential to provide the Southeast United States with access to North Louisiana or East Texas Supplies?

A. Yes. Boardwalk Pipeline is currently in the process of constructing three expansion projects -- the Gulf Crossing Pipeline project, the East Texas to Mississippi Expansion project and the Southeast Expansion Project -- that will serve to transport unconventional supplies to southeast markets. In addition, Kinder Morgan is currently constructing its MidContinent Express Pipeline which will also provide new supply access to shippers in the Southeast. A schematic illustration of SESH as well as the Boardwalk and Kinder Morgan projects is attached as Exhibit TCS-3.

Q. Please provide a description of Boardwalk's Gulf Crossing Pipeline, East Texas to Mississippi Expansion and Southeast Expansion Projects.

A. The Gulf Crossing Pipeline is a newly-created interstate pipeline. This project consists of 357 miles of 42-inch pipeline extending from Sherman, Texas to the Perryville Hub in Northern Louisiana and when completed will have a capacity of approximately 1.7 Bcf/day. At the Perryville Hub, Gulf Crossing can deliver to third party pipelines or directly into Boardwalk's East Texas to Mississippi Expansion. The pipeline portion of the Gulf Crossing Pipeline was completed and placed in service in February 2009 and initial compression is scheduled to be in-service during the first quarter of 2009. The initial capacity of these facilities is 1.2 Bcf/day. In addition, Boardwalk has applied to the Pipeline and Hazardous Materials Safety Administration (PHMSA) of the US Department of Transportation (DOT) for the authority to operate the system at higher operating pressures. If this approval is obtained, capacity on the system will be increased to 1.4 Bcf/day. Finally, the second phase of this project, consisting of compression additions, is scheduled to be in service as of the first quarter of 2010 at which time the project will have a capacity of 1.7 Bcf/day.

Part of Boardwalk's existing Gulf South system, the East Texas to Mississippi Expansion originates at its starting point in Carthage, Texas. This project consists of 242 miles of 42-inch pipeline with approximately 1.7 Bcf of peak-day transmission capacity. Already in-service, the East Texas to Mississippi Expansion aggregates deliveries from intra-state pipelines and carries gas through the Perryville Hub. The East Texas to Mississippi Expansion continues from Perryville and terminates at Harrisville, Mississippi, where the gas can continue along the Southeast Expansion.

Finally, Boardwalk's Southeast Expansion is an expansion of the Gulf South system and is designed to carry gas from the Perryville Hub, Gulf Crossing, and the East Texas to Mississippi Expansion. This Southeast Expansion originates in Harrisville, Mississippi and terminates at Transco Station 85. The initial phase of the project, consisting of 111 miles of 42-inch pipeline and associated compression with a capacity of 1.8 Bcf/day has been constructed and is now in service. In addition, Boardwalk has applied to the

PHMSA for the authority to operate the system at higher operating pressures. If this approval is gained, capacity on the system will be increased to 1.9 Bcf/day.

Q. Please provide a description of the Midcontinent Express Pipeline Project.

A. Midcontinent Express Pipeline is a 50/50 joint venture between Kinder Morgan Energy Partners, L.P. and Energy Transfer Partners, LLC. When the project is completed, the Midcontinent Express Pipeline will consist of approximately 265 miles of 42-inch, 196 miles of 36-inch and 41 miles of 30-inch pipeline, associated compression and up to 13 receipt and/or delivery interconnections. The project will extend from southeast Oklahoma, across northeast Texas, northern Louisiana and central Mississippi, to an interconnection near Transco Station 85 near Butler, Alabama. Midcontinent Express is currently under construction and the first phase of the project extending from Southeast Oklahoma through Delhi, Louisiana has a planned in service date of April 1, 2009 with the remaining pipeline from Delhi, Louisiana to Butler, Alabama planned to be in service on July 15, 2009. The pipeline will have an initial capacity of up to 1.5 Bcf/day with a planned future expansion bringing capacity up to 1.8 Bcf/day.

Q. Please provide a summary of supply sources that will be made available to Southeast markets via the Boardwalk projects and the MidContinent Express projects.

A. Midcontinent Express will provide access to natural gas supplies from the Barnett Shale and Bossier Sands in Texas, the Fayetteville Shale in Arkansas and the Woodford / Caney Shale in Oklahoma.

Boardwalk's Gulf Crossing Pipeline is designed to carry gas from the Barnett and Woodford / Caney shales. Next, Boardwalk's East Texas to Mississippi Expansion taps supplies from the Barnett Shale as well as Bossier Sands. Gas supplies from both of these projects may continue downstream into Boardwalk's Southeast Expansion Project. Exhibit TCS-4 provides an illustration of upstream pipeline capacity available in the vicinity of Transco Station 85 over the past few years and projected into the next few years.

Q. What is the outlook for Barnett, Fayetteville, Haynesville and Woodford/Caney shale gas supplies in the future?

A. Unlike traditional Gulf Coast sources discussed previously in my testimony, unconventional shale gas production has been growing rapidly over the past few years and is projected to continue this rapid growth in the future. According to the Texas Railroad Commission, the Barnett Shale play near Fort Worth, Texas has grown from total annual production of less than 400 Bcf per year or an average of about 1.1 Bcf/day in 2004 to an annual total in excess of 1.4 Tcf or an average of about 3.8 Bcf/day in 2008.

The Fayetteville, Haynesville and Woodford/Caney Shale plays have been developed more recently than the Barnett Shale and production at these fields has been rapidly increasing over the last several years. As per the Arkansas Oil & Gas Commission, Fayetteville Shale production increased from an annual total of 100 MMcf or an average of about 0.3 MMcf/day in 2004 to an annual total of about 273 Bcf or an average of about 750 MMcf/day in 2008 and is expected to continue to grow over the next several years. Finally, the Haynesville Shale and Woodford Shale production sources are in the initial stages of exploration and production. With this said, these plays are also expected to produce significant quantities of natural gas into the grid within the next few years.

Q. Do you believe that there are adequate capacity and supplies upstream of the Transco Station 85 area to meet the demands of the FPL markets?

A. Yes. As discussed previously, after installation of pipeline facilities recently placed in service, currently under construction and planned in the next few years, it is projected that new third party capacity to Transco near its Station 85 will total about 4.7 Bcf/day (1.0 Bcf/day via SESH, 1.9 Bcf/day via Boardwalk Southeast Expansion and 1.8 Bcf/day via MidContinent Express). This capacity coupled with Transco's traditional capacity upstream of its Station 85 of approximately 4.7 Bcf/day can provide a total of about 9.4 Bcf/day to the Transco Station 85 area. This total capacity will be sufficient to meet the demands of all of Transco's customers as well as the demand on the proposed Florida EnergySecure Line.

With respect to gas supplies accessible via this capacity, as previously mentioned, the new pipeline projects are being constructed to transport the growing unconventional supply sources to southeast markets. As discussed in detail above, these unconventional supply sources are projected to continue to grow in the next several years and the Florida EnergySecure Line will provide FPL with access to this growing resource base.

Q. Do you believe that the construction of the aforementioned pipeline projects to provide unconventional supply sources of gas to the Transco Station 85 area will have an impact on gas costs in this area?

A. Yes. I believe that the addition of these incremental natural gas supplies to this area via the planned and recently constructed pipeline facilities will result in downward pressure on localized gas market prices in the Transco Station 85 area versus other natural gas supply locations. This can be confirmed in the marketplace with a review of market values within Transco's Zone 4 (Transco Station 85 is within Transco's Zone 4) over the past few years as well as a review of the market's view of future pricing at this location.

First, with respect to the past few years, prices of natural gas bought and sold in Transco's Zone 4 during 2006 and 2007 (before the installation of SESH in the fall of 2008) carried an average premium of about $0.25/MMBtu versus gas bought and sold at the Henry Hub, Louisiana. By comparison, natural gas bought and sold at this location during the past twelve months (April 2008 through March 2009) carried an average premium of about $0.10/MMBtu versus gas bought and sold at the Henry Hub. This indicates that the introduction of incremental supplies via SESH and other recently installed facilities have already exerted downward pressure and resulted in lower prices in the vicinity of Transco Station 85.

Additionally, a review of basis futures contracts as traded on the NYMEX ClearPort Exchange indicates that prices at this location will likely continue to decline over the next few years. More specifically, the Transco Zone 4 Basis Swap Futures Contracts as traded on the NYMEX ClearPort Exchange reflects the market value for gas bought and sold within Transco's Zone 4 versus the NYMEX futures contract for gas delivered at the Henry Hub for a given month. During March 2009, the average of the monthly settlement prices for this Transco Zone 4 Basis Swap averaged a negative $0.0375 per MMBtu for calendar year 2010. Thus, the forward market currently projects that the value of gas bought and sold within Transco's Zone 4 will continue to decline versus other markets over the next few years.

Q. Do you believe that increased diversity in available supply mix would benefit FPL and the state of Florida?

A. Yes. With the state of Florida generally and FPL specifically reliant to a large degree on Gulf Coast supplies, I believe that the introduction of access to and expanded natural gas supply mix including unconventional shale gas supplies via the proposed Florida EnergySecure Line will provide supply diversity and will correspondingly increase supply reliability. As discussed previously, Gulf Coast production is projected to decline whereas shale gas production is projected to grow in the future. In addition, Gulf Coast production remains subject to disruption due to hurricane activity during the peak summer demand period. Diversification of the supply mix will mitigate the impact of such disruptions on the overall natural gas supply portfolio.

FPL FUEL REQUIREMENTS POSITION VS. INDUSTRY

Q. Please describe FPL's fuel supply mix and reliance upon natural gas as a fuel source.

A. As described in Table I.A.1: Capacity Resource by Unit Type within FPL's "Ten-Year Power Plant Site Plan for 2008-2017," as of December 31, 2007, FPL had a total of 22,135 MW of generating capacity in its portfolio of generating assets. Of this 22,135 MW of generating capacity, 2,939 MW are nuclear facilities, 896 MW are coal facilities, 660 MW are oil facilities, 10,876 MW can be fueled by either fuel oil or natural gas and 6,765 MW can only be fueled with natural gas.

Q. How does the total quantity of natural gas utilized to generate electricity in the state of Florida compare to that of other states?

A. As depicted in the EIA data summarized in Exhibit TCS-5, in a comparison of all fifty states, the state of Florida consumed the third largest quantity of natural gas to generate electricity during 2007. States in which the total amount of power generated using natural gas exceeded that of the state of

Florida included only Texas and California. Further, these three large use states significantly outpace any other state in natural gas utilized to generate electricity. In fact, the state with the fourth largest use of natural gas to generate electricity, New York, utilized only about 50% as much natural gas as that utilized in Florida to generate power. Perhaps more significantly, the total amount of natural gas utilized to generate power in New York was less than that utilized by FPL alone during 2007.

Q. How does natural gas pipeline and supply access in Florida compare to that available in Texas?

A. Texas is a net exporter of natural gas to other states whereas Florida is a net importer of natural gas from other states. In other words, more natural gas is produced than consumed in the state of Texas whereas virtually all of the natural gas consumed in the state of Florida is produced outside of the state. More specifically, within its "Natural Gas Annual 2007" report, the EIA reported that Florida imported a net of 915 Bcf whereas Texas exported a net of 2,276 Bcf of natural gas in 2007. Because there is significantly more gas produced than consumed in the state of Texas while essentially all natural gas consumed in Florida must be imported into the state, it is clear that supply access in Texas is greater than that available in Florida.

Further, the pipeline network in the state of Texas is well developed with numerous intrastate and interstate pipelines traversing the state and providing a competitive environment for natural gas access available to customers within the state. In contrast, access to gas supply in the state of Florida must be obtained via the interstate pipelines operating within the state. With more than forty intrastate pipeline systems and twenty five interstate pipeline systems operating in the state of Texas compared to the state of Florida, which is primarily served by two interstate pipeline systems (Gulfstream and FGT), it is clear that competitive access to transportation capacity available to end-use consumers is more competitive in Texas than in Florida.

Q. How does natural gas pipeline and supply access in Florida compare to that available in California?

A. Like Florida, California is a net importer of natural gas with EIA reporting net natural gas imports to California of 2,103 Bcf in 2007. However, the California marketplace is unique in that natural gas is primarily delivered to the state border by multiple long haul interstate pipelines. The gas is then transported within the state via a network of intrastate pipelines owned and operated by California utilities. As reported by the EIA in its report entitled "U.S. Intrastate Natural Gas Pipeline Systems – April 2007," these systems include the Pacific Gas & Electric (PG&E) pipeline system with approximately 3,500 miles of pipeline in service having a capacity of 3.2 Bcf/day, the Southern California (SoCal) Gas system with approximately 1,900 miles of pipeline in service and a capacity of 4 Bcf/day and the San Diego Gas and Electric (SDG&E) pipeline system with approximately 830 miles of pipeline in service and a capacity of about 900 MMcf/day. As such, unlike the Florida market, the California market is not dependent upon interstate pipelines to deliver natural gas to ultimate consumers within the state, but is only dependent upon such pipelines to transport the gas to the state border. This in effect moves the "point of competition" for natural gas supplies away from individual markets within the state to points of aggregation at the state border. A consumer located on one of these utility systems in California obtains access, via the utility pipeline network, to any of a number of interstate pipelines delivering to the utility pipeline system, which provides the end user with the potential to access multiple supply basins via these upstream interstate pipeline systems. For example, Transwestern Pipeline and El Paso Natural Gas receive supplies from West Texas and San Juan basin sources, Kern River Gas Transmission receives supplies from Rocky Mountain sources and Gas Transmission Northwest (GTN) receives supplies from Canadian and Rocky Mountain sources. Each of these pipelines delivers to the intrastate utility systems, providing end users within California with access to any of these supply sources via the utility pipeline systems. In contrast, within the state of Florida, end use markets (such as FPL generation facilities) can only access supplies made available via the directly connected interstate pipelines of FGT and Gulfstream, which primarily provide access only to Gulf Coast and offshore Gulf of Mexico supply sources.

Q. What conclusions do you make with respect to natural gas supply access in Florida versus access to supplies available in other states that use comparable quantities of natural gas in support of electric generation?

A. As discussed in detail above, California and Texas are the only states that utilize natural gas for electric generation to an extent comparable to that of the state of Florida. Generation facilities in California obtain access to multiple interstate pipeline and supply basin alternatives via an extensive utility intrastate pipeline network operating within the state. In Texas, generation facilities often have access to multiple intrastate and interstate pipeline alternatives. Unlike those in Texas and California, generators operating in Florida, such as FPL, typically have access only to supplies delivered by either Gulfstream or FGT and primarily from only onshore Gulf Coast and offshore Gulf of Mexico supply sources. Thus, I would conclude that gas supply access in Florida is not as robust as that available in comparable states such as Texas and California. As such, efforts to diversify the natural gas supply mix and the delivery pipeline alternatives available to the state of Florida will benefit FPL as well as all consumers in the state and should be pursued.

NEED FOR NEW NATURAL GAS CAPACITY IN FLORIDA

Q. Please describe your understanding of FPL's natural gas transportation capacity requirements supporting the Florida EnergySecure Line.

A. FPL sought and obtained approval from the FPSC in Docket Nos. 080245-EI and 080246-EI to modernize its CCEC and RBEC plants to natural gas fueled combined cycle facilities effective June 2013 and June 2014 respectively. These Modernization Projects will provide a total of 2,426 MW of new electric generation capacity and will each have a peak natural gas demand requirement of approximately 200 MMcf/day. As such, in 2014, FPL will require approximately 400 MMcf/day of incremental natural gas supply to accommodate the needs of these two units.

Q. Can this incremental natural gas demand be met utilizing existing natural gas pipeline infrastructure in the state?

A. No. As mentioned previously in my testimony, the incumbent pipelines serving the state are fully subscribed and will remain almost fully subscribed after completion of proposed expansion projects. As such, the Modernization Projects require the addition of incremental pipeline capacity.

Q. Did FPL consider natural gas supply alternatives other than traditional pipeline expansions such as the use of market area storage or LNG imports to support its future natural gas requirements?

A. Yes. My understanding is that in its initial review process, FPL considered other alternative gas infrastructure options such as the use of market-area storage or LNG imports to meet its incremental demand. However, these alternatives represent supply alternatives rather than capacity and supply alternatives to serve the market. As such, the use of either market area storage or LNG imports would still require the installation of pipeline infrastructure necessary to transport the imported LNG or stored supplies to the ultimate markets at FPL's plant site locations.

Further, with respect to LNG imports, FPL also determined that reliance upon LNG imports located at coastal locations and subject to severe hurricane weather conditions did not provide the supply diversity and security that the company desired when targeting unconventional supplies available at the proposed inlet to the Florida EnergySecure Line project.

Finally, with respect to market area storage facilities there are no known suitable geologic formations within the state of Florida to provide in-ground storage. As such, the only storage that could be constructed in the state would be above ground tank storage. However, FPL anticipates that the generation facilities to be served by the Florida EnergySecure Line will be operated as base load facilities, requiring a consistent supply source to support fuel requirements. As a result, the operating parameters associated with above ground in-tank storage (cycling requirements and total stored capacity available) are not compatible with the baseload supply requirements of these generation assets.

Q. Does FPL's load forecast include any additional natural gas requirements in support of power generation demand beyond the CCEC and RBEC Modernization Projects?

A. Yes. FPL's Base Case Resource Plan as submitted in the testimony of FPL witness Enjamio indicates that FPL will require significant quantities of natural gas in support of generation requirements in 2021 and beyond. In fact, during the years of 2021 through 2040, FPL projects that it will require an incremental 14,931 MW of natural gas fired generation capacity requiring approximately 2.36 Bcf/day of natural gas as fuel to support generation requirements. This 2.36 Bcf/day requirement is incremental to the 400 MMcf/day required in support of the Modernization Projects.

Q. In addition to FPL natural gas demand increases, are third parties in the state of Florida projected to increase natural gas consumption in support of generation requirements?

A. The 2008 Regional Load and Resource Plan published in July 2008 by the Florida Reliability Coordinating Council (FRCC) included a projection of future natural gas consumption in support of natural gas fired generation requirements. At the time the report was published, total natural gas consumption in the state of Florida in support of natural gas fired generation requirements was projected to increase by approximately 23.5% between the years 2012 and 2017 from an annual usage of about 1,021 Bcf/year in 2012 to an annual usage of about 1,261 Bcf/year in 2017. Assuming that this 23.5% increase in demand is accompanied by a 23.5% increase in required transportation capacity into the state, natural gas transportation into the state would need to increase from the Post FGT Phase VIII statewide capacity level of 4.6 Bcf/day in 2012 to a total capacity of 5.7 Bcf/day by the year 2017. FPL's proposed pipeline project would initially provide about 60% of this capacity into the state upon its in-service date in 2014 and could be economically expanded to support 100% of this increased incremental 1.1 Bcf/day of statewide demand for natural gas transportation capacity to support generation requirements.

It is worth noting that since the development of the FRCC Load and Resource Plan, economic conditions in the overall economy have deteriorated. As such, it is reasonable to assume that natural gas demand growth for electric generation in the near future may be slower than that predicted in the FRCC Plan. With this said, while it is likely that natural gas demand growth for electric generation may be delayed, it is unlikely that this growth will not come to fruition in the long-term.

Q. You have discussed natural gas demand to support electric generation. Is there also potential growth in non electric generation related natural gas demand in the state of Florida?

A. EIA data indicates that natural gas demand for electric power generation has represented roughly 80 to 85% of overall natural gas demand in the state of Florida during the past five years. This EIA data also indicates that natural gas demand for residential, commercial and industrial consumers has been relatively flat at about 135 Bcf per year over the past five years. Although this non-electric generation natural gas demand has been relatively flat over the past five years, any increase in this demand will only add to the pressure for additional natural gas pipeline capacity into the state in the future.

Q. Will the Florida EnergySecure Line create a long-term surplus of transportation capacity into Florida?

A. No. As stated above, in its first year of operation in 2014, FPL will require 400 MMcf/day of the initial 600 MMcf/day of Florida EnergySecure Line capacity to meet the fuel requirements of its CCEC and RBEC Modernization Projects. Subsequently, as depicted in the Base Case Resource Plan in FPL witness Enjamio's testimony, FPL will require the entire potential expanded 1.25 Bcf/day of capacity for system operations by the year 2025.

In addition, if (a) economic conditions should change such that FPL's long-term load forecast reverts to conditions similar to earlier projections such as those projected in its 2008 Ten-Year Power Plant Site Plan, or (b) the regulatory process associated with the proposed construction of two new nuclear units at Turkey Point is delayed, FPL may well utilize the remaining 200 MMcf/day of the initial 600 MMcf/day of capacity within the first five years of pipeline operation.

Further, as illustrated in the FRCC's regional load and resource plan, the FRCC projects that natural gas demand to meet electric requirements will expand by approximately 16.5% or an average of about 750,000 MMBtu/day (approximately 750 MMcf/day) by 2015. As mentioned above, while this growth may be delayed due to current economic conditions, the overall demand requirement would exceed the initial 600 MMcf/day capacity of the pipeline project.

Q. With respect to third party demand for natural gas in Florida, would the Florida EnergySecure Line need to be connected to these markets to serve this demand?

A. No. As mentioned above, the proposed pipeline will be connected to FPL's CCEC, RBEC and Martin Plant sites. Additionally, after installation of FGT's Phase VIII project, FPL will have contractual firm transportation rights on the FGT system of up to 744,000 MMBtu/day to the Martin plant, 192,000 MMBtu/day to the CCEC and 180,000 MMBtu/day to the RBEC. Further, FPL maintains firm transportation rights of up to 350,000 MMBtu/day to the Martin Plant on the Gulfstream system. In the event that a third party facility requires natural gas supplies upstream of these points on the FGT or

Gulfstream systems, FPL would have the potential to release its firm transportation capacity from these locations on FGT or Gulfstream to the third party and replace such capacity with incremental capacity on the new pipeline. For example, if a third party required 200 MMcf/day of transportation capacity in the Tampa area (upstream of Martin on FGT or Gulfstream), FPL could release 200 MMcf/day of its own transportation capacity on FGT or Gulfstream currently directed to the FPL Martin Plant to such third party and utilize an additional 200 MMcf/day on the new pipeline to the Martin plant to displace the released capacity.

As such, the new pipeline can provide competitive access to markets throughout the state of Florida utilizing a combination of FPL's existing capacity portfolio as well as capacity made available through construction of the new pipeline.

ADDITIONAL BENEFITS TO FLORIDA OF BUILDING THE FLORIDA ENERGYSECURE LINE VS. EXPANSIONS OF EXISTING SYSTEM

Q. In addition to the infusion of needed pipeline capacity, does the Florida EnergySecure Line provide other enhancements to the natural gas pipeline infrastructure within Florida?

A. Yes. The addition of this pipeline will provide other benefits including improved reliability and security of natural gas deliveries to market areas in

Peninsular Florida, including protection against mainline outages, supply losses and the loss of single pipe service to some locations.

Q. Please describe the protection against mainline outages that can be provided by the new pipeline.

A. As described previously in my testimony, the majority of the gas delivered to Florida markets is delivered via the FGT and Gulfstream pipeline systems. Portions of these pipeline systems have been looped with one or more pipes, which provide a degree of protection in the event service in one pipe is interrupted, while other portions of these systems rely on deliveries through a single pipe. As the new pipeline will provide another source of natural gas into Peninsular Florida it would be available to offset a portion of the delivery capacity lost due to any potential mainline outages on the existing pipelines.

Further, with respect to potential compressor outages, it is important to note that the full utilization of the existing systems is dependent upon the operation of compression facilities located both within Florida as well as upstream on these pipeline systems in other states. As is the case with any pipeline system designed to operate at or near capacity in meeting contractual delivery obligations, the interruption or loss of localized compression or transmission facilities anywhere along the pipeline system can, to some degree, impact the ability of the affected pipeline to meet its firm contractual service requirements at downstream locations. Once again, the introduction of a new large diameter pipeline into this service area will provide another delivery option and will serve to mitigate the impact of any upstream compressor outages on local markets.

Q. The design of the new pipeline initially includes connections to only the FPL markets of RBEC, CCEC and Martin. As such, how can the new pipeline be utilized to provide protection against mainline outages at other locations?

A. In order to provide protection against mainline outages at other locations, the new pipeline can be utilized to displace transportation quantities from connected markets to upstream markets on the affected pipelines. This would not require a direct connection to the existing pipeline. As discussed earlier in my testimony, FPL has firm transportation rights with both Gulfstream and FGT to provide service to FPL's Martin generation plant and has firm transportation contract rights with FGT to its RBEC and CCEC facilities. In the event that there is an outage on the Gulfstream system, FPL could flow natural gas supplies to its Martin Plant via the new pipeline and displace a like amount of capacity on the Gulfstream system. Similarly, in the event that there is a capacity restriction on FGT due to an upstream outage, FPL could flow natural gas supplies to its Martin, RBEC or CCEC facilities via the new pipeline and displace a like amount of capacity on the FGT system.

In addition to displacement, because the new pipeline will be located in the vicinity of both FGT and Gulfstream near FPL's Martin Plant, the pipeline could in the future be connected to the FGT and/or Gulfstream systems at this location to serve additional markets in Florida. (This would require blanket certificate approval from the Federal Energy Regulatory Commission pursuant to 18 C.F.R § 284.224). Further, due to its close proximity to FGT near the RBEC, the new pipeline could in the future also be connected to the FGT system near the RBEC. With direct connections, the new pipeline could be utilized as an operational loop of the existing pipeline systems providing gas supplies into the existing pipelines at these locations. If connections are installed, in the event that there is an outage on either FGT or Gulfstream, the new pipeline could be utilized to provide gas supplies into the affected pipeline to serve Florida markets to offset capacity restrictions created by the outage.

Q. Please describe the protection against single pipe outages provided by the new pipeline.

A. FPL generation facilities at Cape Canaveral and Riviera are currently capable of receiving supplies only from the FGT system. My understanding is that, at each of these locations, FGT delivers into the FPL plants via a single delivery lateral. As such, with the current configuration, in the event that there is a failure of this delivery lateral, the plants would have no available source of gas supply. After connections with the new pipeline are installed at these locations, there will be two pipelines physically connected to each plant (FGT and the new pipeline). This will provide protection against the total loss of natural gas supplies to the plant in the event that there is a failure on one of the two pipelines serving the plant.

Q. Please describe the protection against supply losses that can be provided by the new pipeline.

A. As described in detail previously in my testimony, Gulfstream and FGT are designed to source gas supplies primarily from traditional onshore Gulf Coast and offshore Gulf of Mexico supply sources. The new pipeline will provide supplies from unconventional shale gas locations in North Louisiana, Arkansas and East and Central Texas. This diversity of supply created with the new pipeline will decrease the portion of FPL's fuel requirements that are dependent upon traditional Gulf Coast and Gulf of Mexico sources. As a result, a smaller percentage of FPL's overall supply portfolio (and generation capacity) will be impacted by isolated weather events such as hurricane disruptions in the Gulf of Mexico.

This diversity of supply has the potential to provide an operational benefit through access to non-impacted supply sources during isolated weather events. In addition, recognizing that short-term or long-term reductions in Gulf Coast natural gas supply due to hurricanes can result in spikes in Gulf Coast supply prices, the diversity of supply created via the Florida EnergySecure Line has the potential to also provide a financial benefit through access to non-impacted supply sources during such events.

Q. Will the new pipeline provide FPL and other Florida consumers with increased competitive alternatives for future gas transportation capacity?

A. Yes. The new pipeline will introduce competition to the connected FPL markets of Riviera and Cape Canaveral where today there is no competition for transportation services. In addition, the majority of Peninsular Florida markets are currently accessed only by FGT. The construction of a new large diameter pipeline through Peninsular Florida will provide FPL as well as other Florida customers with access to a competitive large diameter pipeline alternative in this portion of the state. To the benefit of all consumers in these areas, the project will provide pipe-on-pipe competition for interstate pipeline services and will provide consumers with options as to pipeline services in the future. While the option value associated with this type of project is difficult to quantify, a project that permanently alters the competitive environment for services such as the Florida EnergySecure Line project has the potential to reap unforeseen benefits for the participant, as well as other consumers in the vicinity of the pipeline.

THE SOLICITATION PROCESS

Q. What process did FPL use to determine that the Florida EnergySecure Line was the most favorable method to obtain incremental gas transportation capacity to support its natural gas requirements?

A. As discussed in detail in the testimony of FPL witness Stubblefield, in July 2008 FPL issued a solicitation to a broad cross section of pipeline companies for interstate transportation capacity to meet its future transportation requirements (the "Solicitation").

Q. What is your understanding of the goals of FPL's Solicitation process?

A. The goals of the Solicitation were to meet the fuel supply needs of FPL's Modernization Projects, increase physical pipeline capacity into the state of Florida, add to the reliability and diversity of supply available to the state and insure future transportation capacity availability.

Q. Were these goals addressed in the Solicitation?

A. Yes. The Solicitation clearly stated that in addition to meeting the gas delivery needs of the CCEC and RBEC, FPL's goals included finding a solution that would also ensure future gas transportation availability and diversity of supply. In addition, FPL further stated in the Solicitation that one option under consideration was the development of a new intrastate pipeline system to insure that FPL's long-term needs could be met. To this end, FPL stated in the Solicitation that "proposals to deliver supplies directly to its Cape Canaveral and Riviera markets using new or existing pipeline facilities would be considered but that any perceived economic benefit of such proposals would be weighed against their more limited role in meeting FPL's long-term needs."

Q. **Please describe the pipeline project alternatives requested in the Solicitation.**

A. Within the initial Solicitation, FPL requested that bidders provide proposals as to one or more of three alternatives. These included: (Option 1) a pipeline with a primary receipt point at Transco Station 85 and a primary delivery point at FPL plants (Cape Canaveral, Riviera, et al); (Option 2(a)) a pipeline with a primary receipt point at Transco Station 85 and a primary delivery point near FGT Station 16; and (Option 2(b)) a pipeline with a primary receipt point near FGT Station 16 and primary delivery points at the above referenced FPL plants.

Once again, with respect to Option 2(b), FPL also notified the bidders that it was also considering an FPL-developed intrastate pipeline as an alternative to the third party proposals.

Q. **Please describe the transportation service quantities requested in the Solicitation.**

A. The initial Solicitation included a request for three delivery quantity scenarios. These scenarios included requests for (i) 1.0 Bcf/day, (ii) 800 MMcf/day and (iii) 400 MMcf/day to various FPL delivery points in the state of Florida. All scenarios included a requirement that 200 MMcf/day be deliverable to the

RBEC and approximately 200 MMcf/day be deliverable to the CCEC. In addition, the scenarios required deliveries to other FPL sites at varying quantities.

After issuing the initial Solicitation, FPL's internal forecast of generation facility requirements was revised downward such that it was clear that the 1.0 Bcf/day and 800 MMcf/day service quantity levels would exceed FPL's fuel requirements in the near future. It also became apparent that due to economies of scale required with these projects, a 400 MMcf/day project originating at Transco Station 85 would not significantly reduce overall costs versus a 600 MMcf/day project from this location and would limit potential for expansions in the future. As such, FPL followed up the initial Solicitation with an additional request that the bidders develop updated proposals with a service quantity of 600 MMcf/day.

Q. Did bidders respond to FPL's Solicitation?

A. Yes. FPL received proposals from seven different pipeline bidders with each bidder providing multiple proposals.

Q. After reviewing bids received in the Solicitation process, did FPL identify the proposals that provided the lowest cost opportunities for FPL's customers?

A. Yes. As discussed in detail in the testimony of FPL witness Stubblefield, after review of the proposals received in response to its Solicitation, FPL determined that among the proposals received from third party bidders, the proposal from Company B coupled with a pipeline project from the chosen supply location of Transco Station 85 to Company B's proposed project receipt point represented the lowest cost opportunity for FPL's customers. In addition, FPL further determined that the combination of the Upstream Pipeline Project with its Florida EnergySecure Line project also provided a low cost alternative for its customers.

Q. **Did the proposal that FPL received from Company B provide access to the preferred Transco Station 85 supply location?**

A. No. The proposal received from Company B did not provide access to the preferred Transco Station 85 supply location.

Q. **As Company B did not include facilities in its proposal to transport gas supplies from FPL's chosen supply location near Transco Station 85, did you develop an analysis to approximate the cost of facilities to transport supplies from Transco Station 85 to Company B's proposed project receipt point?**

A. Yes. As depicted on Exhibit TCS-6, I have developed an approximate facility design and cost estimate to transport 600 MMcf/day of natural gas supplies from Transco Station 85 to the supply location included within the Company B proposal and have developed an approximate cost of service for such facilities based upon recent comparable projects. As illustrated in the Exhibit, I estimate that this lateral extension would add a cost of service of approximately $0.20 per MMBtu of design capacity plus required compressor fuel retention of about 0.30%.

Q. In comparing the proposals received in response to its Solicitation process, do you believe that FPL applied its evaluation criteria in an objective and fair manner?

A. Yes. FPL utilized consistent criteria in evaluating the bid proposals and developed its comparison analyses of the various bids in an objective and fair manner.

Q. Based upon your review of the Solicitation and bid responses, do you agree with FPL's initial assessment that the Upstream Pipeline Project as proposed by Company E combined with the Florida EnergySecure Line project and the proposal from Company B are the two lowest cost opportunities available that meet the goals of the Solicitation?

A. Yes. I agree with FPL's assessment that these were the two lowest cost opportunities available that met the goals of the Solicitation.

Q. Do you believe that FPL's Solicitation process was effective in providing FPL with a comprehensive view of pipeline infrastructure alternatives available in the marketplace versus the Florida EnergySecure Line project?

A. Yes. As stated above, FPL issued its Solicitation to a broad cross section of pipeline companies active in the Southeastern United States. Furthermore, the Solicitation, while specific with respect to the requested receipt and delivery points, provided the bidders with flexibility as to facilities to install and as to the structure of the bids. Through this process, FPL obtained various alternative bid proposals from various bidders. In addition, after initial bids were received, FPL continued discussions and negotiations with bidders that presented the most cost effective alternatives and subsequently received refined proposals from these bidders. I believe that this process was effective in providing FPL with a full understanding of pipeline alternatives available in the marketplace.

GAS COST SAVINGS ANALYSIS

Q. Did you develop an independent evaluation of the overall cost of gas impact associated with the Florida EnergySecure Line versus competitive proposals received by FPL in its solicitation process?

A. Yes. As described in the testimony of FPL witness Stubblefield, the lowest cost proposal received by FPL (other than the combined Upstream Pipeline Project / Florida EnergySecure Line project) was the proposal received from Company B. As such, I have developed an independent comparative cost analysis between this proposal from Company B and the combined Upstream Pipeline Project / Florida EnergySecure Line. This comparative analysis is attached as Exhibit TCS-7.

Q. Did the results of this analysis favor the Florida EnergySecure Line or Company B's pipeline expansion proposal?

A. The results of this analysis, which include, in my opinion, very favorable assumptions regarding costs associated with the proposal received from

Company B, still favor the Florida EnergySecure Line alternative. These results are illustrated on Page 1 of the Exhibit TCS-7.

Q. Please describe the "very favorable" assumptions you referred to above regarding the proposal received from Company B.

A. In this analysis, it is assumed that Company B's proposal will have the same competitive impact on costs paid by FPL and other consumers within the state of Florida as the construction of a new pipeline into this area. More specifically, the analysis evaluates direct delivery costs only and there has been no adjustment made to the analysis to reflect the fact that the introduction of a new incremental pipeline into Peninsular Florida will introduce pipe-on-pipe competition and will change the competitive landscape in this portion of the state for pipeline services. Obviously, this assumption gives Company B's proposal a significant "benefit of the doubt" associated with the value of future competitive alternatives in the state.

Q. Please describe the Gas Cost Savings analysis.

A. The Gas Cost Savings Analysis compares costs that would be incurred by FPL and its customers for pipeline service during the forty year project life of the Florida EnergySecure Line to costs that would be incurred by FPL and its customers for pipeline service utilizing the Company B proposal alternative.

Q. Please provide a summary of FPL's natural gas fuel requirements for power generation included in the Gas Cost Savings Analysis.

A. The natural gas fuel requirements included in the Gas Cost Savings Analysis represent the next 1,187,500 MMBtu/day (approximately 1.2 Bcf/day) of FPL projected natural gas fuel requirements from FPL's load resource plan. The initial demand associated with the planned CCEC and RBEC Modernization Projects will occur in late 2012 or early 2013 in support of the testing and certification of the CCEC facility. Subsequent to this initial demand, fuel requirements increase through start up of the CCEC and RBEC as well as subsequent capacity additions added in each of the years 2021 through 2026.

Q. **What future expansion capacity cost assumptions were utilized in the analyses with respect to the Florida EnergySecure Line?**

A. The Florida EnergySecure Line project in Peninsular Florida will consist of approximately 280 miles of 30-inch pipeline that will initiate at the terminus of the proposed Upstream Pipeline Project and terminate at FPL's Martin Plant with lateral extensions to the CCEC and RBEC. The pipeline will have an initial design capacity of 600 MMcf/day and is designed to accommodate low cost future expansions through the installation of one or more mid-line compressor stations.

While the initial design capacity of the new pipeline will total only 600 MMcf/day, a high pressure (1480 psig MAOP) 30-inch pipeline with supporting compression can support flows in the range of 1.2 Bcf/day to 1.3 Bcf/day. As a result of this expandability via compression, significant market expansion can occur along this pipeline without the need to install additional mainline pipeline facilities. Future low cost expandability of this system is a significant benefit of this system versus expansion of the incumbent pipelines.

With this said, FPL, in conjunction with its third party pipeline contractor developed analyses of facilities and associated costs for the initial project installation at a capacity of 600 MMcf/day as well as expansion increments bringing the capacity up to levels of 800 MMcf/day, 1 Bcf/day and 1.25 Bcf/day. Further, based upon the facility and cost estimates provided, FPL utilized its financial models to develop annual revenue requirements required by the company to offset the costs of installation associated with the initial project as well as each tranche of expansion capacity. I have utilized these annual revenue requirement projections as provided by FPL's financial model to represent the cost impact that the project installation would have on FPL's customers.

Q. What future expansion capacity cost assumptions were utilized in the analyses with respect to the Upstream Pipeline Project?

A. As a result of the Solicitation process, FPL and Company E have agreed to a transaction reservation fee and a commodity fee with a transportation quantity of 600,000 MMBtu/day (approximately 600 MMcf/day). The transactional rate is utilized in the analysis for the first 600,000 MMBtu/day of transportation capacity. Next, reviewing bids received from Company E in response to FPL's Solicitation for the Upstream Pipeline Project at capacity levels of 800,000 MMBtu/day (approximately 800 MMcf/day) and 1,000,000

MMBtu/day (approximately 1 Bcf/day) reveals that bids were slightly (less than 5%) lower as capacity requirements increased. While this could imply that successive capacity expansions of the Upstream Pipeline Project will be slightly lower in cost than the first expansion, in order to be conservative in cost assumptions, the Gas Cost Savings Analysis incorporates an assumption that the cost of each successive expansion of the Upstream Pipeline Project will have a consistent cost basis with the initial project cost. As such, we have utilized a constant dollar cost equal to the negotiated transaction rates to represent all Upstream Pipeline Project expansion costs through the project life.

Q. Do you believe that this is a conservative assumption with respect to the cost associated with successive expansions of the Upstream Pipeline Project?

A. Yes. It is important to note that the Upstream Pipeline Project includes the installation of a section of large diameter (36-inch) pipeline that could support transport quantities in excess of 1 Bcf/day without the need for pipeline looping. As such, with respect to this pipeline segment, successive expansions will likely not require looping and/or installation of additional pipeline. This would indicate that successive expansions could likely be accomplished at a lower cost on the Upstream Pipeline Project than the initial project. As such, I believe that holding expansion costs of the Upstream Pipeline Project constant is a conservative assumption that generally overstates expansion costs.

Q. What future expansion capacity cost assumptions were utilized in the analyses with respect to the proposal received from Company B?

A. The rate included in Company B's 400,000 MMBtu/day proposal is utilized in the analysis to represent the cost of this first 400,000 MMBtu/day of capacity. Next, reviewing bids received from Company B in response to FPL's Solicitation for service levels of 400,000 MMBtu/day and 600,000 MMBtu/day reveals that Company B's capacity bid for 600,000 MMBtu/day of capacity was slightly (less than 5%) lower than it's bid for 400,000 MMBtu/day of capacity. As such, similar to the Upstream Pipeline Project expansion assumption, in the Gas Cost Savings Analysis, an assumption has been included that the cost of each successive expansion of the Company B system will have a consistent cost basis with the initial project cost.

Q. Did you make any assumptions with respect to FPL's ability to recover a portion of the cost associated with any excess capacity created via the installation of the Florida EnergySecure Line?

A. Yes. As noted previously, the Florida EnergySecure Line and the Upstream Pipeline Project will each have an initial capacity in January 2014 of about 600 MMcf/day (approximately 600,000 MMBtu/day). FPL's current load forecast indicates that FPL will require about 400,000 MMBtu/day (approximately 400 MMcf/day) of natural gas to support incremental generation facilities in 2014. Further, timing of successive planned expansions of the Florida EnergySecure Line will not exactly coincide with FPL fuel requirements through the project life. As such, during the initial years of the project and periodically during later years, there will be capacity available on the project in excess of that needed to support FPL generation requirements. As discussed in detail earlier in my testimony, in order to recover costs of excess capacity, FPL can either sell excess capacity on its new pipeline system to third party shippers or can utilize the excess capacity on the new pipeline for its own account and release a like amount of capacity on either the Gulfstream or FGT systems to third party shippers. In order to reflect potential cost recoveries associated with these releases, the Gas Cost Savings Analysis assumes that FPL releases excess capacity to third parties and thereby recovers a portion of its capacity costs. Finally, it is worth noting that the analysis values excess capacity at one price for the whole of the project (i.e., the Upstream Pipeline Project capacity and the Florida EnergySecure Line capacity) thereby assuming that the capacity values are related to the entire path from the supply point near Transco Station 85 to the ultimate delivery point locations in the state of Florida.

Q. What capacity cost recovery value did you assign to the excess capacity in the Gas Cost Savings Analysis?

A. Four excess capacity cost recovery value scenarios were utilized to develop four separate Gas Cost Savings Analysis cases. The Gas Cost Savings Analysis identified as Case A incorporates an assumption that FPL obtains a cost recovery for excess capacity equal to the average value paid for capacity on the secondary market by FPL during 2008. The Gas Cost Savings Analysis identified as Case B incorporates an assumption that FPL obtains a cost recovery for excess capacity equal to the maximum tariff rate associated with the transportation capacity in FPL's portfolio that has the highest corresponding tariff rate (FGT's proposed Phase VIII expansion maximum tariff recourse rate). Finally, as a worst case assumption, the Gas Cost Savings Analysis identified as Case C incorporates an assumption that there is no cost recovery for excess capacity.

Q. What were the results of the analyses set forth in Exhibits TCS-7?

A. As depicted on Exhibits TCS-7, in all three cases the Gas Cost Savings Analysis favors the Florida EnergySecure Line / Upstream Pipeline Project alternative. In fact, the Net Present Value of savings utilizing the Florida EnergySecure Line / Upstream Pipeline Project alternative versus the Company B alternative range from about $230 million to about $900 million.

THE FLORIDA ENERGYSECURE LINE IS THE RIGHT CHOICE

Q. Is FPL's decision to initiate the Florida EnergySecure Line the right choice for FPL and its customers?

A. Yes. The Florida EnergySecure Line meets FPL's stated goals of increasing physical pipeline capacity into the state of Florida, adding to the reliability and diversity of supply available to the state, ensuring future transportation capacity availability and meeting the fuel supply needs of FPL's CCEC and RBEC Modernization Projects. In addition, the economic results depicted in the Gas Cost Analyses in Exhibits TCS-7, reveal that the Florida

EnergySecure Line has favorable economic results versus the most competitive proposal received via the Solicitation process. Finally, the Project also introduces a competitive pipeline alternative and an associated option value to markets in Peninsular Florida where today there is no pipeline competition. While it is difficult to quantify the option value associated with a project of this nature, the introduction of meaningful pipeline competition into Peninsular Florida has the potential to provide unforeseen benefits for FPL and its customers as well as other natural gas consumers in these areas.

Q. Does this conclude your testimony?

A. Yes.

TIMOTHY C. SEXTON

EMPLOYMENT HISTORY

Gas Supply Consulting, Inc.
14811 St. Mary's, Suite 175, Houston, Texas 77079

June 1994 - Present
Position: Vice President

Selected Experience at Gas Supply Consulting, Inc.

- Natural Gas Infrastructure Analysis – Analyzed capabilities of pipeline systems in Florida to support potential natural gas fired generation installations at various locations in Florida on behalf of Florida Power & Light Company, assessed capabilities of natural gas infrastructure in Florida to meet statewide generation fuel requirements on behalf of the Florida Reliability Coordinating Council, analyzed capability of local pipeline infrastructure to receive large quantities of natural gas from proposed regasified LNG facilities in various states on behalf of large LNG importer client, analyzed natural gas pipeline infrastructure and potential infrastructure expansions available to meet utility clients natural gas demand in Wisconsin.
- Solicitation and Acquisition of Natural Gas Supplies and Services – Actively involved in and directed natural gas supply and natural gas pipeline service capacity acquisition for utility and industrial clients. Developed RFPs, interacted with suppliers, negotiated agreement terms and negotiated contracts on behalf of clients.
- Long Term Fuel Supply Plan Development – Prepared long term fuel supply plans for power generation development clients operating in various states for use in attracting project financing and/or for filing with state commissions as required in regulatory process to obtain construction authorizations.
- Consulting for End User Clients – Work with clients assessing natural gas use and requirements, prepare corporate gas supply purchasing plan outlining recommended corporate purchasing strategy. Structure recommended transactions regarding supply, service and price risk management programs. Implement purchasing program on behalf of clients through negotiation of transactions with various suppliers, utilities and service providers.
- Consulting for Other Portions of the Energy Industry – Performed consulting services for a broad spectrum of clients, both domestically and internationally, including gas marketing companies, natural gas producers, transportation and storage service providers, and customer groups.

United Gas Pipeline Company (currently Gulf South Pipe Line Company)

July 1993 - June 1994
Position: Regional Manager (Supply Services)

- Attracted incremental supplies to the United Gas Pipeline system by structuring service transactions and aggressively pursuing incremental gas supplies;
- Maintained exising supplies on the United Gas Pipeline system by structuring and negotiating long-term transportation agreements with connected producers;
- Cultivated relationships with onsystem gas suppliers to insure that the needs of such suppliers were met on a timely and consistent basis.

United Gas Pipeline Company (currently Gulf South Pipe Line Company)

June 1989 - July 1993
Position: Staff Engineer (Operations Department)
Associate Engineer (Engineering Department)
Engineer (System Planning Department)

Filled various positions of increasing responsibility within the operations, engineering, planning and marketing departments of Koch Gateway Pipeline Company, and its predecessor United Gas Pipeline Company, over this four-year period.

EDUCATION

University of Houston, Houston, Texas
Masters in Business Administration (Concentration in Finance), July 1993

University of Texas, Austin, Texas
Bachelor of Science Degree in Civil Engineering, May 1989

OTHER

Currently Licensed as a Professional Engineer in the State of Texas

Florida Pipeline Capacity Load Factor Calculation

Month	Natural Gas Delivered to Consumers in Florida (Including Vehicle Fuel) (MMcf) [1/]	Average Daily Quantity of Natural Gas to Florida Consumers (MMcf/day)	FGT Capacity into Florida (MMcf/day) [2/]	Gulfstream Capacity into Florida (MMcf/day) [3/]	Cypress Capacity into Florida (MMcf/day) [4/]	Gulf South Capacity into Florida (MMcf/day) [5/]	Total Pipeline Capacity into Florida (MMcf/day)	Load Factor (Daily Use as % of Transport Capacity)
Dec-2007	67,153	2,166	2,209	1,114	220	190	3,733	58%
Jan-2008	67,031	2,162	2,209	1,114	220	190	3,733	58%
Feb-2008	62,878	2,168	2,209	1,114	220	190	3,733	58%
Mar-2008	72,402	2,336	2,209	1,114	220	190	3,733	63%
Apr-2008	77,101	2,570	2,209	1,114	220	190	3,733	69%
May-2008	87,941	2,837	2,209	1,114	336	190	3,849	74%
Jun-2008	89,266	2,976	2,209	1,114	336	190	3,849	77%
Jul-2008	91,019	2,936	2,209	1,114	336	190	3,849	76%
Aug-2008	97,544	3,147	2,209	1,114	336	190	3,849	82%
Sep-2008	86,186	2,873	2,209	1,114	336	190	3,849	75%
Oct-2008	77,163	2,489	2,209	1,114	336	190	3,849	65%
Nov-2008	63,073	2,102	2,209	1,114	336	190	3,849	55%
Total	938,757							67%
Jun-Sept								78%

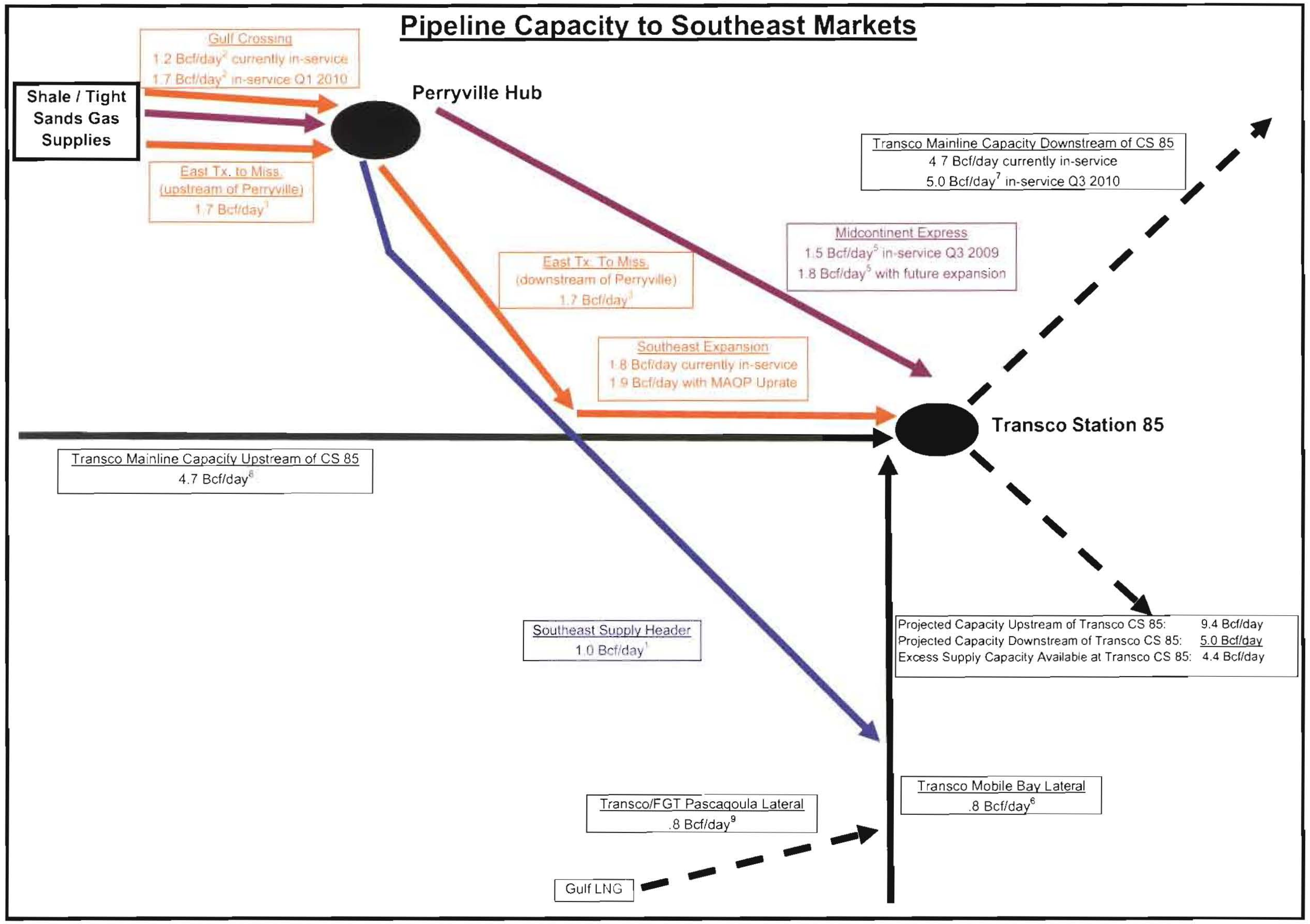
[1/] *Natural Gas Delivered to Consumers in Florida data sourced from consumption tables on website of the Energy Information Administration of the US Department of Energy (link: http://tonto.eia.doe.gov/dnav/ng/hist/n3060fl2m.htm).*

[2/] *Represents the design capacity through FGT's Compressor Stations 11 and 11A just upstream of the Florida state line and is sourced from Part A (Public and Non-Internet Public Information) of FGT's Annual System Flow Diagrams Report (Form 567) for the year 2007 as filed by FGT on June 1, 2008.*

[3/] *Gulfstream Capacity into Florida represents capacity as of September 1, 2008 listed as "Maximum Firm Capacity" through Gulfstream's Station 420 on Gulfstream's Electronic Bulletin Board under the tab entitled "Unsubscribed Capacity".*

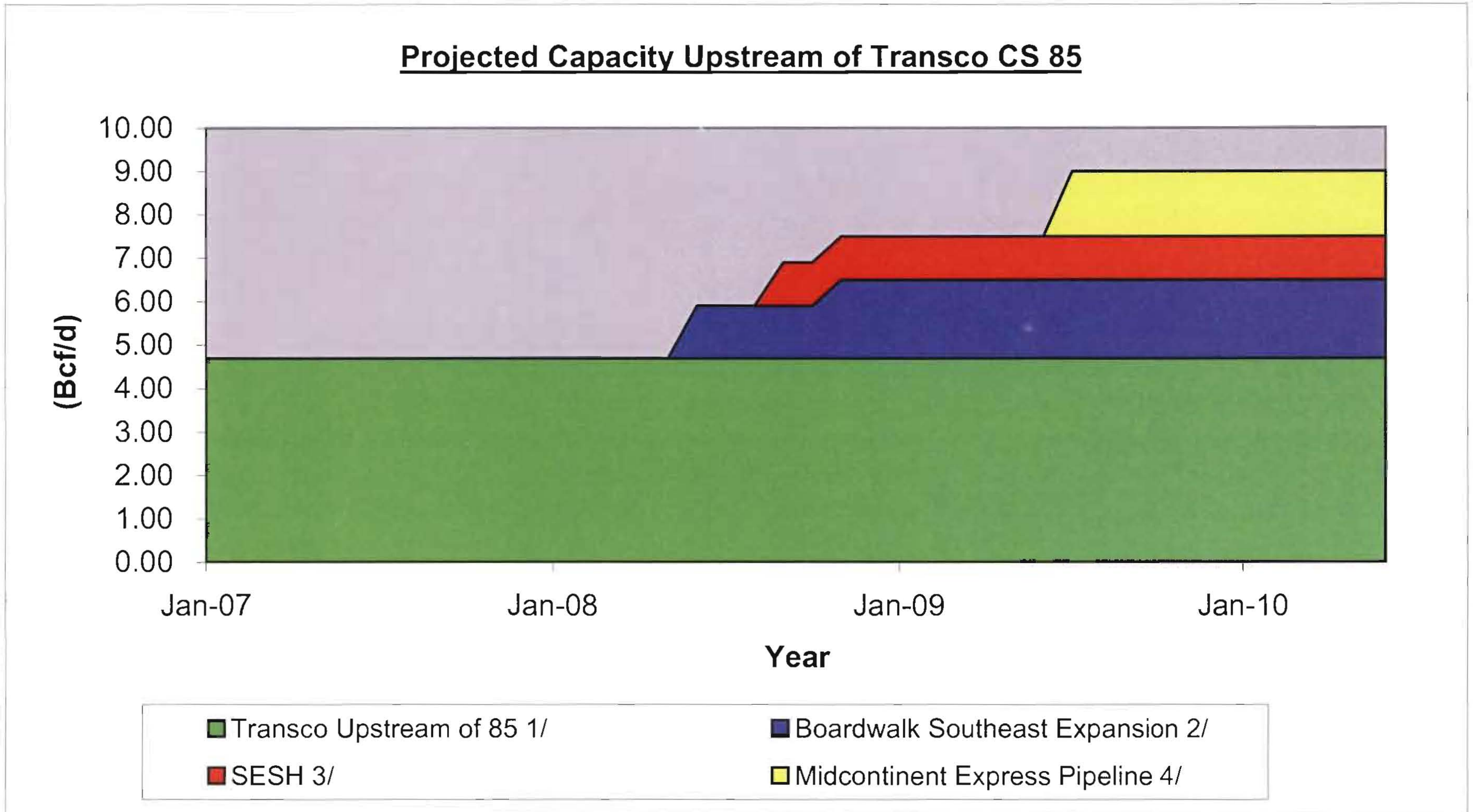
[4/] *Cypress Capacity represents Phase I capacity in service as of May 1, 2007 and Phase II capacity in service as of May 1, 2008 as depicted on the Cypress Pipeline website at link www.cypresspipeline.com.*

[5/] *Gulf South capacity into Florida as per EIA report entitled "Interstate Pipeline Capacity on a State-to-State Level" available at the following weblink: http://www.eia.doe.gov/pub/oil_gas/natural_gas/analysis_publications/ngpipeline/StatetoState.xls.*



[1] Spectra Energy's website: http://www.spectraenergy.com/what_we_do/businesses/us/assets/sesh/
[2] Gulf Crossing website: http://www.gulfcrossing.com/ProjectGC.aspx
[3] Boardwalk Gulf South Pipeline website http://www.gulfsouthpl.com/ExpansionProjects.aspx?id=785
[4] Boardwalk Gulf South Pipeline website. http://www.gulfsouthpl.com/ExpansionProjects.aspx?id=787
[5] Midcontinent Express Pipeline website: http://www.midcontinentexpress.com/News_release_internal.asp?code=7
[6] Transco Pipeline website: http://www.1line.williams.com/Files/Transco/TranscoInfoPostingFrameset.html
[7] FERC website: http://www.ferc.gov/ Transcontinental Pipeline's Request for Pre-Filing Review regarding 85 North Expansion Project Docket #PF08-21-000.
[8] FERC website: http://www.ferc.gov/ Transcontinental Pipeline's Application for Certificate of Public Convenience and Necessity (Momentum Expansion Project) Docket #CP01-388-000.
[9] Transco Pipeline website: http://www.1line.williams.com/Files/Transco/TranscoInfoPostingFrameset.html

Docket No. 09____-EI
Schematic illustration entitled Capacity to Southeast Markets
Exhibit TCS-3, Page 1 of 1



[1/] Transcontinental Pipeline's Application for Certificate of Public Convenience and Necessity (Momentum Expansion Project) Docket #CP01-388-000.

[2] Boardwalk Gulf South Pipeline website: http://www.gulfsouthpl.com/ExpansionProjects.aspx?id=785

[3] Spectra Energy's website: http://www.spectraenergy.com/what_we_do/businesses/us/assets/sesh/

[4] Midcontinent Express Pipeline website: http://www.midcontinentexpress.com/News_release_internal.asp?code=7

Total Industry - 2007 Fuel Use for Generation by State per EIA

State	Coal (Short Tons)	State	Natural Gas (Mcf)	State	Other Gases (MMBtu)	State	Petroleum (Barrels)
TX	102,915,788	TX	1,557,467,131	TX	24,744	TX	2,699,279
CA	836,652	CA	860,418,088	CA	16,120	CA	4,486,653
FL	28,518,027	FL	775,930,007	FL	82	FL	33,151,762
NY	9,543,964	NY	398,102,590	NY	0	NY	13,855,150
LA	15,462,729	LA	379,661,007	LA	11,560	LA	4,636,252
OK	20,585,844	OK	287,092,543	OK	125	OK	266,872
AZ	21,296,832	AZ	279,637,794	AZ	0	AZ	89,310
MA	5,129,102	MA	187,294,571	MA	0	MA	5,208,456
MS	9,895,491	MS	184,958,601	MS	210	MS	720,755
AL	37,230,701	AL	180,433,849	AL	2,703	AL	236,641
NV	3,446,770	NV	171,658,943	NV	40	NV	24,955
NJ	4,499,820	NJ	147,064,539	NJ	2,079	NJ	895,649
PA	55,490,146	PA	142,280,600	PA	8,350	PA	2,665,044
CO	19,287,757	CO	123,005,046	CO	23	CO	64,963
GA	40,976,098	GA	122,043,388	GA	0	GA	784,578
OR	2,577,187	OR	104,618,128	OR	0	OR	15,891
MI	36,801,697	MI	102,347,005	MN	1,983	MI	1,260,707
VA	14,430,111	VT	90,658,114	UT	0	VT	3,408,354
CT	1,838,605	CT	73,046,330	CT	35	CT	2,341,244
IL	57,062,208	IL	66,150,433	IL	1,030	IL	273,262
AR	15,652,503	AR	60,447,829	AR	0	AR	149,816
NM	15,958,762	NM	57,885,176	NM	0	NM	82,351
UT	17,064,801	UT	57,645,374	VA	0	UT	73,487
WI	24,080,440	WI	54,497,378	WA	0	WI	1,927,027
WA	5,689,233	WA	52,243,425	WI	1,987	WA	48,581
RI	0	RI	51,815,261	RI	0	RI	77,316
SC	16,612,236	SC	49,861,942	SC	0	SC	414,065
ME	71,304	ME	47,448,773	MI	0	ME	1,101,979
AK	498,186	AK	41,945,565	AK	0	AK	1,847,958
MO	44,209,134	MO	40,890,265	MO	37	MO	139,715
NC	32,300,133	NC	40,396,869	NC	0	NC	741,845
NH	1,625,233	NH	39,619,806	NH	0	NH	653,846
IN	60,624,931	IN	35,642,674	IN	25,358	IN	293,899
OH	59,546,036	OH	34,874,144	OH	1,821	OH	2,098,628
MN	19,665,192	MN	34,181,437	MN	323	MN	811,090
IA	23,454,310	IA	25,968,547	IA	0	IA	707,004
KS	22,779,650	KS	25,651,861	KS	0	KS	470,111
MD	11,937,518	MD	21,481,869	MD	4,703	MD	1,790,746
KY	41,064,161	KY	20,887,254	KY	53	KY	5,565,579
DE	2,483,969	DE	16,764,454	DE	8,201	DE	446,081
ID	19,448	ID	12,326,337	ID	0	ID	240
NE	12,275,170	NE	10,941,958	NE	0	NE	76,698
TN	27,621,231	TN	8,228,135	TN	68	TN	345,015
WY	26,628,197	WY	4,396,066	WY	2,280	WY	84,884
SD	1,690,652	SD	4,235,097	SD	0	SD	139,713
WV	38,067,847	WV	4,048,525	WV	317	WV	356,736
MT	11,928,925	MT	1,044,933	MT	187	MT	824,077
ND	24,731,044	ND	76,706	ND	230	ND	99,291
VT	0	VA	25,947	VT	0	VA	20,538
DC	0	DC	0	DC	0	DC	197,313
HI	689,627	HI	0	HI	254	HI	13,943,232
US-TOTAL	**1,046,795,402**	**US-TOTAL**	**7,089,342,314**	**US-TOTAL**	**114,904**	**US-TOTAL**	**112,614,638**

Source Link: http://www.eia.doe.gov/cneaf/electricity/epa/consumption_state.xls

Data from [redacted] Used to Approximate Required First Year Cost Recovery of [redacted] from Transco Station 85 [redacted]

Pipeline Project	Cost Estimate ($)	MDQ (MMBtu/day)	Proposed Negotiated Rate [1/] ($/MMBtu/day)	1'st Year Cost Recovery (%)
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

Data from [redacted] Used to Approximate Cost of Pipeline Installation from Transco CS 85 [redacted].

	Pipe ID (inches)	Length (miles)	Cost Estimate ($)	Calculated Average Pipe Cost ($/in-diam-mile)	Capacity (MMBtu/day)	Proposed In Service Date
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

Estimated Cost and Calculated Approximate Cost of Service of Pipeline from Transco CS 85 [redacted].

	Pipeline Length [2/] (miles)	Pipe ID (inches)	Unit Cost of Pipeline [3/] ($/in-diam-Mile)	Required Compression [4/] HP	Unit Cost of Compression $/HP	Total Cost ($)	Contract MDQ (MMBtu/day)	1'st Year Cost Recovery (%)	Calculated Unit Cost of Service ($/MMBtu)
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

1/ [redacted]

2/ Pipeline Length based upon distance between [redacted] and the Transco Compressor Station 85.

3/ Unit Cost of Pipeline (in $/in-diam-mile) is equal to average unit cost of [redacted] escalated by inflation rate of 2.5% per year from 2011 to 2012.

4/ Required Compression calculated as compression required to deliver 600,000 MMBtu/day [redacted] at assumed required pressure of 900 psig assuming a receipt pressure of 800 psig from Transco. Fuel retention calculated as approximately equal to 0.32% of throughput.

Docket No. 09____-EI
Approximate Cost of Service to Transport Natural Gas from Transco CS 85 to Company B Project
Exhibit TCS-6, Page 1 of 1
[Confidential]

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

Case	Excess Capacity Value Assumptions	Net Savings ($MM)	NPV of Savings ($MM)
Case A	(a) Excess capacity sold at current market values for secondary capacity. (b) Underutilized capacity economically dispatched by FPL to FPL Plants.	$7,811	$453
Case B	(a) Excess capacity sold at FGT Proposed Phase VIII Project Recourse Rate. (b) Underutilized capacity economically dispatched by FPL to FPL Plants.	$8,933	$897
Case C	(a) Excess capacity retained by FPL. (b) Excess and Underutilized capacity economicallly dispatched by FPL to FPL Plants.	$6,962	$233

Docket No. 09_____-EI
Gas Cost Savings Analysis
Exhibit TCS-7, Page 2 of 24

Summary Comparative Cost Analysis

Case A - Excess Capacity Valued at 2008 Market Value

	Company B Proposal				Upstream Pipeline Project - Florida EnergySecure Line Project 1/							
Year	Demand Charges to Company B ($/Year)	Annual Cost of Fuel Retention Gas ($/Year)	Value of Capacity Release Credits ($/Year)	Net Gas Transport Costs ($/Year)	Demand Charges on Upstream Pipeline Project ($/Year)	Annual Florida EnergySecure Line Revenue Requirements ($/Year)	Annual Cost of Fuel Gas Retained / Consumed ($/Year)	Upstream Pipeline Project Commodity Charges ($/Year)	Value of Capacity Release Credits ($/Year)	Net Gas Transport Costs ($/Year)	Potential Savings Associated with Economic Dispatch Activity ($/Year)	Florida Energy Secure Line vs. Company B Net Savings ($/Year)
Column	1	2	3	4	5	6	7	8	9	10	11	12
Source	Attachment I	Attachment II, Col 14	Attachment VB, Col 5	Column 1 + Column 2 + Column 3	Attachment IIIB	Attachment IIIA, Column 8	Attachment IV, Col 13	Attachment IV, Col 16	Attachment VA, Col 5	Sum of Columns 5 through 9	Attachment VI A, Col 16	Column 4 - Column 10 + Column 11
2012	[redacted]	[redacted]	($2,385,639)	[redacted]	[redacted]	$25,429,102	[redacted]	[redacted]	$0	[redacted]	$ -	[redacted]
2013	[redacted]	[redacted]	($11,374,467)	[redacted]	[redacted]	$16,748,820	[redacted]	[redacted]	$0	[redacted]	$ -	[redacted]
2014	[redacted]	[redacted]	($37,787,231)	[redacted]	[redacted]	$288,374,607	[redacted]	[redacted]	($44,124,646)	[redacted]	$ 5,828,278	[redacted]
2015	[redacted]	[redacted]	N/A	[redacted]	[redacted]	$278,493,512	[redacted]	[redacted]	($33,957,721)	[redacted]	$ 4,133,139	[redacted]
2016	[redacted]	[redacted]	N/A	[redacted]	[redacted]	$267,187,914	[redacted]	[redacted]	($34,902,024)	[redacted]	$ 3,676,767	[redacted]
2017	[redacted]	[redacted]	N/A	[redacted]	[redacted]	$256,609,825	[redacted]	[redacted]	($35,676,830)	[redacted]	$ 3,492,079	[redacted]
2018	[redacted]	[redacted]	N/A	[redacted]	[redacted]	$246,685,353	[redacted]	[redacted]	($36,568,751)	[redacted]	$ 3,539,604	[redacted]
2019	[redacted]	[redacted]	N/A	[redacted]	[redacted]	$237,347,420	[redacted]	[redacted]	($37,482,970)	[redacted]	$ 3,941,567	[redacted]
2020	[redacted]	[redacted]	N/A	[redacted]	[redacted]	$228,424,559	[redacted]	[redacted]	($38,525,305)	[redacted]	$ 4,533,935	[redacted]
2021	[redacted]	[redacted]	N/A	[redacted]	[redacted]	$219,638,646	[redacted]	[redacted]	($21,864,117)	[redacted]	$ 5,856,337	[redacted]
2022	[redacted]	[redacted]	N/A	[redacted]	[redacted]	$210,855,067	[redacted]	[redacted]	($4,456,380)	[redacted]	$ 6,986,102	[redacted]
2023	[redacted]	[redacted]	N/A	[redacted]	[redacted]	$223,950,971	[redacted]	[redacted]	($10,516,113)	[redacted]	$ 5,583,921	[redacted]
2024	[redacted]	[redacted]	N/A	[redacted]	[redacted]	$229,621,800	[redacted]	[redacted]	($35,127,779)	[redacted]	$ 4,820,803	[redacted]
2025	[redacted]	[redacted]	N/A	[redacted]	[redacted]	$272,442,660	[redacted]	[redacted]	($52,480,334)	[redacted]	$ -	[redacted]
2026	[redacted]	[redacted]	N/A	[redacted]	[redacted]	$260,520,128	[redacted]	[redacted]	($14,155,879)	[redacted]	$ -	[redacted]
2027	[redacted]	[redacted]	N/A	[redacted]	[redacted]	$248,431,383	[redacted]	[redacted]	($14,509,776)	[redacted]	$ -	[redacted]
2028	[redacted]	[redacted]	N/A	[redacted]	[redacted]	$236,546,383	[redacted]	[redacted]	($14,913,268)	[redacted]	$ -	[redacted]
2029	[redacted]	[redacted]	N/A	[redacted]	[redacted]	$226,038,819	[redacted]	[redacted]	($15,244,334)	[redacted]	$ -	[redacted]
2030	[redacted]	[redacted]	N/A	[redacted]	[redacted]	$218,048,644	[redacted]	[redacted]	($15,625,442)	[redacted]	$ -	[redacted]
2031	[redacted]	[redacted]	N/A	[redacted]	[redacted]	$211,315,829	[redacted]	[redacted]	($16,016,078)	[redacted]	$ -	[redacted]
2032	[redacted]	[redacted]	N/A	[redacted]	[redacted]	$204,612,370	[redacted]	[redacted]	($16,461,457)	[redacted]	$ -	[redacted]
2033	[redacted]	[redacted]	N/A	[redacted]	[redacted]	$197,884,875	[redacted]	[redacted]	($16,826,892)	[redacted]	$ -	[redacted]
2034	[redacted]	[redacted]	N/A	[redacted]	[redacted]	$191,197,743	[redacted]	[redacted]	($17,247,565)	[redacted]	$ -	[redacted]
2035	[redacted]	[redacted]	N/A	[redacted]	[redacted]	$184,516,658	[redacted]	[redacted]	($17,678,754)	[redacted]	$ -	[redacted]
2036	[redacted]	[redacted]	N/A	[redacted]	[redacted]	$177,871,805	[redacted]	[redacted]	($18,170,368)	[redacted]	$ -	[redacted]
2037	[redacted]	[redacted]	N/A	[redacted]	[redacted]	$171,188,230	[redacted]	[redacted]	($18,573,741)	[redacted]	$ -	[redacted]
2038	[redacted]	[redacted]	N/A	[redacted]	[redacted]	$164,611,149	[redacted]	[redacted]	($19,038,084)	[redacted]	$ -	[redacted]
2039	[redacted]	[redacted]	N/A	[redacted]	[redacted]	$158,275,795	[redacted]	[redacted]	($19,514,036)	[redacted]	$ -	[redacted]
2040	[redacted]	[redacted]	N/A	[redacted]	[redacted]	$152,371,651	[redacted]	[redacted]	($20,056,687)	[redacted]	$ -	[redacted]
2041	[redacted]	[redacted]	N/A	[redacted]	[redacted]	$146,968,757	[redacted]	[redacted]	($20,501,934)	[redacted]	$ -	[redacted]
2042	[redacted]	[redacted]	N/A	[redacted]	[redacted]	$141,788,923	[redacted]	[redacted]	($21,014,483)	[redacted]	$ -	[redacted]
2043	[redacted]	[redacted]	N/A	[redacted]	[redacted]	$136,614,736	[redacted]	[redacted]	($21,539,845)	[redacted]	$ -	[redacted]
2044	[redacted]	[redacted]	N/A	[redacted]	[redacted]	$131,446,318	[redacted]	[redacted]	($22,138,829)	[redacted]	$ -	[redacted]
2045	[redacted]	[redacted]	N/A	[redacted]	[redacted]	$126,283,794	[redacted]	[redacted]	($22,630,299)	[redacted]	$ -	[redacted]
2046	[redacted]	[redacted]	N/A	[redacted]	[redacted]	$121,865,958	[redacted]	[redacted]	($23,196,057)	[redacted]	$ -	[redacted]
2047	[redacted]	[redacted]	N/A	[redacted]	[redacted]	$117,454,275	[redacted]	[redacted]	($23,775,958)	[redacted]	$ -	[redacted]
2048	[redacted]	[redacted]	N/A	[redacted]	[redacted]	$113,048,878	[redacted]	[redacted]	($24,437,125)	[redacted]	$ -	[redacted]
2049	[redacted]	[redacted]	N/A	[redacted]	[redacted]	$108,649,904	[redacted]	[redacted]	($24,979,616)	[redacted]	$ -	[redacted]
2050	[redacted]	[redacted]	N/A	[redacted]	[redacted]	$104,257,493	[redacted]	[redacted]	($25,604,107)	[redacted]	$ -	[redacted]
2051	[redacted]	[redacted]	N/A	[redacted]	[redacted]	$99,630,311	[redacted]	[redacted]	($26,244,209)	[redacted]	$ -	[redacted]
2052	[redacted]	[redacted]	N/A	[redacted]	[redacted]	$95,005,139	[redacted]	[redacted]	($26,974,014)	[redacted]	$ -	[redacted]
2053	[redacted]	[redacted]	N/A	[redacted]	[redacted]	$90,382,030	[redacted]	[redacted]	($27,572,822)	[redacted]	$ -	[redacted]
						Upstream Pipeline Project / Florida Energy Secure line vs. Company B Net Savings						$ 7,811,400,108
						Upstream Pipeline Project / Florida Energy Secure line vs. Company B (@2012) 8.35% NPV Savings						$ 453,395,071

1/ As the Florida EnergySecure Line Project and the Upstream Pipeline project are not projected to be in service prior to January 2014, costs for this option in 2012 and 2013 represent short-term workaround costs required to enable testing and initial usage of the CCEC and RBEC during these years. It is assumed that these initial needs would be served via a combination of (a) re-allocation of firm transportation entitlement rights on FGT (b) acquisition of secondary market capacity and (c) the installation of onsite compression at the CCEC and RBEC as required to increase pressure of delivered gas on FGT to required levels. The RBEC compression costs are embedded in overall Energy Secure Line project estimate and the CCEC on-site compression cost is added at a level of $25 million (as estimated by FPL. In addition, as a conservative assumption, it is assumed that secondary capacity required during these years is consistent with quantities purchased from Company B under the Company B alternative and is purchased at market values (same value as release capacity is presumed sold). Finally, transportation fuel and usage costs are assumed identical to those with Company B service as the gas would be delivered via Company B during these years with this alternative.

Summary Comparative Cost Analysis

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

	Company B Proposal				Upstream Pipeline Project - Florida EnergySecure Line Project 1/							
Year	Demand Charges to Company B ($/Year)	Annual Cost of Fuel Retention Gas ($/Year)	Value of Capacity Release Credits ($/Year)	Net Gas Transport Costs ($/Year)	Demand Charges on Upstream Pipeline Project ($/Year)	Annual Florida EnergySecure Line Revenue Requirements ($/Year)	Annual Cost of Fuel Gas Retained / Consumed ($/Year)	Upstream Pipeline Project Commodity Charges ($/Year)	Value of Capacity Release Credits ($/Year)	Net Gas Transport Costs ($/Year)	Potential Savings Associated with Economic Dispatch Activity ($/Year)	Florida Energy Secure Line vs. Company B Net Savings ($/Year)
Column	1	2	3	4	5	6	7	8	9	10	11	12
Source	Attachment I	Attachment II, Col 14	Attachment VB, Col 7	Column 1 + Column 2 + Column 3	Attachment IIIB	Attachment IIIA, Column 11	Attachment IV, Col 13	Attachment IV, Col 16	Attachment VA, Col 7	Sum of Columns 5 through 9	Attachment VI A, Col 16	Column 4 - Column 10 + Column 11
2012	[redacted]	[redacted]	$ (7,214,935)	[redacted]	[redacted]	$26,474,701	[redacted]	[redacted]	$0	[redacted]	$ -	[redacted]
2013	[redacted]	[redacted]	$ (77,857,870)	[redacted]	[redacted]	$57,560,910	[redacted]	[redacted]	$0	[redacted]	$ -	[redacted]
2014	[redacted]	[redacted]	N/A	[redacted]	[redacted]	$288,374,607	[redacted]	[redacted]	($151,643,803)	[redacted]	$ 5,828,278	[redacted]
2015	[redacted]	[redacted]	N/A	[redacted]	[redacted]	$278,493,512	[redacted]	[redacted]	($113,856,572)	[redacted]	$ 4,133,139	[redacted]
2016	[redacted]	[redacted]	N/A	[redacted]	[redacted]	$267,187,914	[redacted]	[redacted]	($114,168,508)	[redacted]	$ 3,676,767	[redacted]
2017	[redacted]	[redacted]	N/A	[redacted]	[redacted]	$256,609,825	[redacted]	[redacted]	($113,856,572)	[redacted]	$ 3,492,079	[redacted]
2018	[redacted]	[redacted]	N/A	[redacted]	[redacted]	$246,685,353	[redacted]	[redacted]	($113,856,572)	[redacted]	$ 3,539,604	[redacted]
2019	[redacted]	[redacted]	N/A	[redacted]	[redacted]	$237,347,420	[redacted]	[redacted]	($113,856,572)	[redacted]	$ 3,941,567	[redacted]
2020	[redacted]	[redacted]	N/A	[redacted]	[redacted]	$228,424,559	[redacted]	[redacted]	($114,168,508)	[redacted]	$ 4,533,935	[redacted]
2021	[redacted]	[redacted]	N/A	[redacted]	[redacted]	$219,638,646	[redacted]	[redacted]	($63,213,278)	[redacted]	$ 5,856,337	[redacted]
2022	[redacted]	[redacted]	N/A	[redacted]	[redacted]	$210,855,067	[redacted]	[redacted]	($12,569,984)	[redacted]	$ 6,986,102	[redacted]
2023	[redacted]	[redacted]	N/A	[redacted]	[redacted]	$223,950,971	[redacted]	[redacted]	($28,939,025)	[redacted]	$ 5,583,921	[redacted]
2024	[redacted]	[redacted]	N/A	[redacted]	[redacted]	$229,621,800	[redacted]	[redacted]	($94,309,508)	[redacted]	$ 4,820,803	[redacted]
2025	[redacted]	[redacted]	N/A	[redacted]	[redacted]	$272,442,660	[redacted]	[redacted]	($137,460,369)	[redacted]	$ -	[redacted]
2026	[redacted]	[redacted]	N/A	[redacted]	[redacted]	$260,520,128	[redacted]	[redacted]	($36,173,781)	[redacted]	$ -	[redacted]
2027	[redacted]	[redacted]	N/A	[redacted]	[redacted]	$248,431,383	[redacted]	[redacted]	($36,173,781)	[redacted]	$ -	[redacted]
2028	[redacted]	[redacted]	N/A	[redacted]	[redacted]	$236,546,383	[redacted]	[redacted]	($36,272,888)	[redacted]	$ -	[redacted]
2029	[redacted]	[redacted]	N/A	[redacted]	[redacted]	$226,038,819	[redacted]	[redacted]	($36,173,781)	[redacted]	$ -	[redacted]
2030	[redacted]	[redacted]	N/A	[redacted]	[redacted]	$218,048,644	[redacted]	[redacted]	($36,173,781)	[redacted]	$ -	[redacted]
2031	[redacted]	[redacted]	N/A	[redacted]	[redacted]	$211,315,829	[redacted]	[redacted]	($36,173,781)	[redacted]	$ -	[redacted]
2032	[redacted]	[redacted]	N/A	[redacted]	[redacted]	$204,612,370	[redacted]	[redacted]	($36,272,888)	[redacted]	$ -	[redacted]
2033	[redacted]	[redacted]	N/A	[redacted]	[redacted]	$197,884,875	[redacted]	[redacted]	($36,173,781)	[redacted]	$ -	[redacted]
2034	[redacted]	[redacted]	N/A	[redacted]	[redacted]	$191,197,743	[redacted]	[redacted]	($36,173,781)	[redacted]	$ -	[redacted]
2035	[redacted]	[redacted]	N/A	[redacted]	[redacted]	$184,516,658	[redacted]	[redacted]	($36,173,781)	[redacted]	$ -	[redacted]
2036	[redacted]	[redacted]	N/A	[redacted]	[redacted]	$177,871,805	[redacted]	[redacted]	($36,272,888)	[redacted]	$ -	[redacted]
2037	[redacted]	[redacted]	N/A	[redacted]	[redacted]	$171,188,230	[redacted]	[redacted]	($36,173,781)	[redacted]	$ -	[redacted]
2038	[redacted]	[redacted]	N/A	[redacted]	[redacted]	$164,611,149	[redacted]	[redacted]	($36,173,781)	[redacted]	$ -	[redacted]
2039	[redacted]	[redacted]	N/A	[redacted]	[redacted]	$158,275,795	[redacted]	[redacted]	($36,173,781)	[redacted]	$ -	[redacted]
2040	[redacted]	[redacted]	N/A	[redacted]	[redacted]	$152,371,651	[redacted]	[redacted]	($36,272,888)	[redacted]	$ -	[redacted]
2041	[redacted]	[redacted]	N/A	[redacted]	[redacted]	$146,968,757	[redacted]	[redacted]	($36,173,781)	[redacted]	$ -	[redacted]
2042	[redacted]	[redacted]	N/A	[redacted]	[redacted]	$141,788,923	[redacted]	[redacted]	($36,173,781)	[redacted]	$ -	[redacted]
2043	[redacted]	[redacted]	N/A	[redacted]	[redacted]	$136,614,736	[redacted]	[redacted]	($36,173,781)	[redacted]	$ -	[redacted]
2044	[redacted]	[redacted]	N/A	[redacted]	[redacted]	$131,446,318	[redacted]	[redacted]	($36,272,888)	[redacted]	$ -	[redacted]
2045	[redacted]	[redacted]	N/A	[redacted]	[redacted]	$126,283,794	[redacted]	[redacted]	($36,173,781)	[redacted]	$ -	[redacted]
2046	[redacted]	[redacted]	N/A	[redacted]	[redacted]	$121,865,958	[redacted]	[redacted]	($36,173,781)	[redacted]	$ -	[redacted]
2047	[redacted]	[redacted]	N/A	[redacted]	[redacted]	$117,454,275	[redacted]	[redacted]	($36,173,781)	[redacted]	$ -	[redacted]
2048	[redacted]	[redacted]	N/A	[redacted]	[redacted]	$113,048,878	[redacted]	[redacted]	($36,272,888)	[redacted]	$ -	[redacted]
2049	[redacted]	[redacted]	N/A	[redacted]	[redacted]	$108,649,904	[redacted]	[redacted]	($36,173,781)	[redacted]	$ -	[redacted]
2050	[redacted]	[redacted]	N/A	[redacted]	[redacted]	$104,257,493	[redacted]	[redacted]	($36,173,781)	[redacted]	$ -	[redacted]
2051	[redacted]	[redacted]	N/A	[redacted]	[redacted]	$99,630,311	[redacted]	[redacted]	($36,173,781)	[redacted]	$ -	[redacted]
2052	[redacted]	[redacted]	N/A	[redacted]	[redacted]	$95,005,139	[redacted]	[redacted]	($36,272,888)	[redacted]	$ -	[redacted]
2053	[redacted]	[redacted]	N/A	[redacted]	[redacted]	$90,382,030	[redacted]	[redacted]	($36,173,781)	[redacted]	$ -	[redacted]
						Upstream Pipeline Project / Florida Energy Secure line vs. Company B Net Savings						$ 8,933,363,977
						Upstream Pipeline Project / Florida Energy Secure line vs. Company B (@2012) 8.35% NPV Savings						$ 896,913,707

1/ As the Florida EnergySecure Line Project and the Upstream Pipeline project are not projected to be in service prior to January 2014, costs for this option in 2012 and 2013 represent short-term workaround costs required to enable testing and initial usage of the CCEC and RBEC during these years. It is assumed that these initial needs would be served via a combination of (a) re-allocation of firm transportation entitlement rights on FGT (b) acquisition of secondary market capacity and (c) the installation of onsite compression at the CCEC and RBEC as required to increase pressure of delivered gas on FGT to required levels. The RBEC compression costs are embedded in overall Energy Secure Line project estimate and the CCEC on-site compression cost is added at a level of $25 million (as estimated by FPL. In addition, as a conservative assumption, it is assumed that secondary capacity required during these years is consistent with quantities purchased from Company B under the Company B alternative and is purchased at market values (same value as release capacity is presumed sold). Finally, transportation fuel and usage costs are assumed identical to those with Company B service as the gas would be delivered via Company B during these years with this alternative.

Summary Comparative Cost Analysis

Case C - Excess Capacity Given No Value in Marketplace

Year	Company B Proposal				Upstream Pipeline Project - Florida EnergySecure Line Project 1/							
	Demand Charges to Company B ($/Year)	Annual Cost of Fuel Retention Gas ($/Year)	Value of Capacity Release Credits ($/Year)	Net Gas Transport Costs ($/Year)	Demand Charges on Upstream Pipeline Project ($/Year)	Annual Florida EnergySecure Line Revenue Requirements ($/Year)	Annual Cost of Fuel Gas Retained / Consumed ($/Year)	Upstream Pipeline Project Commodity Charges ($/Year)	Value of Capacity Release Credits ($/Year)	Net Gas Transport Costs ($/Year)	Potential Savings Associated with Economic Dispatch Activity ($/Year)	Florida Energy Secure Line vs. Company B Net Savings ($/Year)
Column	1	2	3	4	5	6	7	8	9	10	11	12
Source	Attachment I	Attachment II, Col 14	Attachment VB, Col 9	Column 1 + Column 2 + Column 3	Attachment III	Attachment IIIA, Column 14	Attachment IV, Col 13	Attachment IV, Col 16	Attachment VA, Col 9	Sum of Columns 5 through 9	Attachment VI B, Col 16	Column 3 - (Column 10 - Column 11)
2012	[redacted]	$ -	$0	[redacted]	[redacted]	$25,000,000	[redacted]	[redacted]	$0	[redacted]	$ -	[redacted]
2013	[redacted]	$ 10,111,164	$0	[redacted]	[redacted]	$0	[redacted]	[redacted]	$0	[redacted]	$ -	[redacted]
2014	[redacted]	$ 27,496,720	$0	[redacted]	[redacted]	$288,374,607	[redacted]	[redacted]	$0	[redacted]	$ 15,029,194	[redacted]
2015	[redacted]	$ 35,646,988	$0	[redacted]	[redacted]	$278,493,512	[redacted]	[redacted]	$0	[redacted]	$ 11,328,875	[redacted]
2016	[redacted]	$ 39,853,091	$0	[redacted]	[redacted]	$267,187,914	[redacted]	[redacted]	$0	[redacted]	$ 11,178,973	[redacted]
2017	[redacted]	$ 43,404,627	$0	[redacted]	[redacted]	$256,609,825	[redacted]	[redacted]	$0	[redacted]	$ 11,328,223	[redacted]
2018	[redacted]	$ 47,367,421	$0	[redacted]	[redacted]	$246,685,353	[redacted]	[redacted]	$0	[redacted]	$ 11,868,681	[redacted]
2019	[redacted]	$ 51,136,030	$0	[redacted]	[redacted]	$237,347,420	[redacted]	[redacted]	$0	[redacted]	$ 12,902,034	[redacted]
2020	[redacted]	$ 52,543,249	$0	[redacted]	[redacted]	$228,424,559	[redacted]	[redacted]	$0	[redacted]	$ 13,906,389	[redacted]
2021	[redacted]	$ 64,100,375	$0	[redacted]	[redacted]	$219,638,646	[redacted]	[redacted]	$0	[redacted]	$ 11,104,481	[redacted]
2022	[redacted]	$ 77,111,429	$0	[redacted]	[redacted]	$210,855,067	[redacted]	[redacted]	$0	[redacted]	$ 8,041,577	[redacted]
2023	[redacted]	$ 102,583,566	$0	[redacted]	[redacted]	$223,950,971	[redacted]	[redacted]	$0	[redacted]	$ 7,072,966	[redacted]
2024	[redacted]	$ 117,153,656	$0	[redacted]	[redacted]	$229,621,800	[redacted]	[redacted]	$0	[redacted]	$ 8,562,322	[redacted]
2025	[redacted]	$ 144,060,449	$0	[redacted]	[redacted]	$272,442,660	[redacted]	[redacted]	$0	[redacted]	$ -	[redacted]
2026	[redacted]	$ 172,326,039	$0	[redacted]	[redacted]	$260,520,128	[redacted]	[redacted]	$0	[redacted]	$ -	[redacted]
2027	[redacted]	$ 175,759,610	$0	[redacted]	[redacted]	$248,431,383	[redacted]	[redacted]	$0	[redacted]	$ -	[redacted]
2028	[redacted]	$ 179,752,972	$0	[redacted]	[redacted]	$236,546,383	[redacted]	[redacted]	$0	[redacted]	$ -	[redacted]
2029	[redacted]	$ 182,834,115	$0	[redacted]	[redacted]	$226,038,819	[redacted]	[redacted]	$0	[redacted]	$ -	[redacted]
2030	[redacted]	$ 186,477,823	$0	[redacted]	[redacted]	$218,048,644	[redacted]	[redacted]	$0	[redacted]	$ -	[redacted]
2031	[redacted]	$ 190,194,397	$0	[redacted]	[redacted]	$211,315,829	[redacted]	[redacted]	$0	[redacted]	$ -	[redacted]
2032	[redacted]	$ 194,516,761	$0	[redacted]	[redacted]	$204,612,370	[redacted]	[redacted]	$0	[redacted]	$ -	[redacted]
2033	[redacted]	$ 197,852,001	$0	[redacted]	[redacted]	$197,884,875	[redacted]	[redacted]	$0	[redacted]	$ -	[redacted]
2034	[redacted]	$ 201,796,033	$0	[redacted]	[redacted]	$191,197,743	[redacted]	[redacted]	$0	[redacted]	$ -	[redacted]
2035	[redacted]	$ 205,818,937	$0	[redacted]	[redacted]	$184,516,658	[redacted]	[redacted]	$0	[redacted]	$ -	[redacted]
2036	[redacted]	$ 210,497,420	$0	[redacted]	[redacted]	$177,871,805	[redacted]	[redacted]	$0	[redacted]	$ -	[redacted]
2037	[redacted]	$ 214,107,701	$0	[redacted]	[redacted]	$171,188,230	[redacted]	[redacted]	$0	[redacted]	$ -	[redacted]
2038	[redacted]	$ 218,376,811	$0	[redacted]	[redacted]	$164,611,149	[redacted]	[redacted]	$0	[redacted]	$ -	[redacted]
2039	[redacted]	$ 222,731,293	$0	[redacted]	[redacted]	$158,275,795	[redacted]	[redacted]	$0	[redacted]	$ -	[redacted]
2040	[redacted]	$ 227,795,246	$0	[redacted]	[redacted]	$152,371,651	[redacted]	[redacted]	$0	[redacted]	$ -	[redacted]
2041	[redacted]	$ 231,703,238	$0	[redacted]	[redacted]	$146,968,757	[redacted]	[redacted]	$0	[redacted]	$ -	[redacted]
2042	[redacted]	$ 236,324,219	$0	[redacted]	[redacted]	$141,788,923	[redacted]	[redacted]	$0	[redacted]	$ -	[redacted]
2043	[redacted]	$ 241,037,609	$0	[redacted]	[redacted]	$136,614,736	[redacted]	[redacted]	$0	[redacted]	$ -	[redacted]
2044	[redacted]	$ 246,518,805	$0	[redacted]	[redacted]	$131,446,318	[redacted]	[redacted]	$0	[redacted]	$ -	[redacted]
2045	[redacted]	$ 250,749,045	$0	[redacted]	[redacted]	$126,283,794	[redacted]	[redacted]	$0	[redacted]	$ -	[redacted]
2046	[redacted]	$ 255,750,899	$0	[redacted]	[redacted]	$121,865,958	[redacted]	[redacted]	$0	[redacted]	$ -	[redacted]
2047	[redacted]	$ 260,852,779	$0	[redacted]	[redacted]	$117,454,275	[redacted]	[redacted]	$0	[redacted]	$ -	[redacted]
2048	[redacted]	$ 266,785,608	$0	[redacted]	[redacted]	$113,048,878	[redacted]	[redacted]	$0	[redacted]	$ -	[redacted]
2049	[redacted]	$ 271,364,658	$0	[redacted]	[redacted]	$108,649,904	[redacted]	[redacted]	$0	[redacted]	$ -	[redacted]
2050	[redacted]	$ 276,778,777	$0	[redacted]	[redacted]	$104,257,493	[redacted]	[redacted]	$0	[redacted]	$ -	[redacted]
2051	[redacted]	$ 282,301,168	$0	[redacted]	[redacted]	$99,630,311	[redacted]	[redacted]	$0	[redacted]	$ -	[redacted]
2052	[redacted]	$ 288,722,853	$0	[redacted]	[redacted]	$95,005,139	[redacted]	[redacted]	$0	[redacted]	$ -	[redacted]
2053	[redacted]	$ 293,679,462	$0	[redacted]	[redacted]	$90,382,030	[redacted]	[redacted]	$0	[redacted]	$ -	[redacted]

Upstream Pipeline Project / Florida Energy Secure line vs. Company B Net Savings	$ 6,961,944,691
Upstream Pipeline Project / Florida Energy Secure line vs. Company B (@2012) 8.35% NPV Savings	$ 232,799,677

1/ As the Florida EnergySecure Line Project and the Upstream Pipeline project are not projected to be in service prior to January 2014, costs for this option in 2012 and 2013 represent short-term workaround costs required to enable testing and initial usage of the CCEC and RBEC during these years. It is assumed that these initial needs would be served via a combination of (a) re-allocation of firm transportation entitlement rights on FGT (b) acquisition of secondary market capacity and (c) the installation of onsite compression at the CCEC and RBEC as required to increase pressure of delivered gas on FGT to required levels. The RBEC compression costs are embedded in overall Energy Secure Line project estimate and the CCEC on-site compression cost is added at a level of $25 million (as estimated by FPL. In addition, as a conservative assumption, it is assumed that secondary capacity required during these years is consistent with quantities purchased from Company B under the Company B alternative and is purchased at market values (same value as release capacity is presumed sold). Finally, transportation fuel and usage costs are assumed identical to those with Company B service as the gas would be delivered via Company B during these years with this alternative.

ATTACHMENT I:

Project Demand Charges Incurred with Company B Offer

Annual Cost Escalator	**2.50%**
Company B Fuel Rate	[redacted]
Transco 85 to Company B Fuel Rate	**0.30%**

Year	2012	2013	2014	2015	2016	2017	2018
Company B Proposed Rate - Escalated at 2.5% per year 1/	[redacted]						
Rate for Potential Pipeline from Transco 85 to Company B - Escalated at 2.5% per year 2/	N/A	$ 0.200	$ 0.202	$ 0.207	$ 0.212	$ 0.217	$ 0.223
FPL Demand (MMBtu/day)			400,000	400,000	400,000	400,000	400,000
Company B Base Proposal							
Company B MDQ (MMBtu/day)	50,000	400,000	400,000	400,000	400,000	400,000	400,000
Company B Res. Fee ($/MMBtu)	[redacted]						
MDQ on Transco 85 to Company B ($/MMBtu) (grossed up for Company B Fuel)	-	413,479	413,479	413,479	413,479	413,479	413,479
Transco 85 to Company B Reservation Charge ($/MMBtu)	$ -	$ 0.200	$ 0.200	$ 0.200	$ 0.200	$ 0.200	$ 0.200
Capacity Addition 1							
MDQ (MMBtu/day)			-	-	-	-	-
Reservation Charge ($/MMBtu)	[redacted]						
MDQ on Transco 85 to Company B ($/MMBtu) (grossed up for Company B Fuel)			-	-	-	-	-
Transco 85 to Company B Reservation Charge ($/MMBtu)			$ -	$ -	$ -	$ -	$ -
Capacity Addition 2							
MDQ (MMBtu/day)							
Reservation Charge ($/MMBtu)	[redacted]						
MDQ on Transco 85 to Company B ($/MMBtu) (grossed up for Company B Fuel)			-	-	-	-	-
Transco 85 to Company B Reservation Charge ($/MMBtu)			$ -	$ -	$ -	$ -	$ -
Capacity Addition 3							
MDQ (MMBtu/day)							
Reservation Charge ($/MMBtu)	[redacted]						
MDQ on Transco 85 to Company B ($/MMBtu) (grossed up for Company B Fuel)			-	-	-	-	-
Transco 85 to Company B Reservation Charge ($/MMBtu)			$ -	$ -	$ -	$ -	$ -
Capacity Addition 4							
MDQ (MMBtu/day)							
Reservation Charge ($/MMBtu)	[redacted]						
MDQ on Transco 85 to Company B ($/MMBtu) (grossed up for Company B Fuel)			-	-	-	-	-
Transco 85 to Company B Reservation Charge ($/MMBtu)			$ -	$ -	$ -	$ -	$ -
Capacity Addition 5							
MDQ (MMBtu/day)			-	-	-	-	-
Reservation Charge ($/MMBtu)	[redacted]						
MDQ on Transco 85 to Company B ($/MMBtu) (grossed up for Company B Fuel)			-	-	-	-	-
Transco 85 to Company B Reservation Charge ($/MMBtu)			$ -	$ -	$ -	$ -	$ -
Capacity Addition 6							
MDQ (MMBtu/day)			-	-	-	-	-
Reservation Charge ($/MMBtu)	[redacted]						
MDQ on Transco 85 to Company B ($/MMBtu) (grossed up for Company B Fuel)			-	-	-	-	-
Transco 85 to Company B Reservation Charge ($/MMBtu)			$ -	$ -	$ -	$ -	$ -
Annual Cost of Reservation Charges	[redacted]						

1/ 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.

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

ATTACHMENT I:

Project Demand Charges Incurred with Company B Offer

Annual Cost Escalator
Company B Fuel Rate [redacted]
Transco 85 to Company B Fuel Rate **0.30%**

Year	2019	2020	2021	2022	2023	2024	2025	2026
Company B Proposed Rate - Escalated at 2.5% per year 1/	[redacted]							
Rate for Potential Pipeline from Transco 85 to Company B - Escalated at 2.5% per year 2/	$ 0.228	$ 0.234	$ 0.240	$ 0.246	$ 0.252	$ 0.258	$ 0.265	$ 0.271
FPL Demand (MMBtu/day)	400,000	400,000	487,500	575,000	750,000	837,500	1,012,500	1,187,500
Company B Base Proposal								
Company B MDQ (MMBtu/day)	400,000	400,000	400,000	400,000	400,000	400,000	400,000	400,000
Company B Res. Fee ($/MMBtu)	[redacted]							
MDQ on Transco 85 to Company B ($/MMBtu) (grossed up for Company B Fuel)	413,479	413,479	413,479	413,479	413,479	413,479	413,479	413,479
Transco 85 to Company B Reservation Charge ($/MMBtu)	$ 0.200	$ 0.200	$ 0.200	$ 0.200	$ 0.200	$ 0.200	$ 0.200	$ 0.200
Capacity Addition 1								
MDQ (MMBtu/day)	[redacted]							
Reservation Charge ($/MMBtu)								
MDQ on Transco 85 to Company B ($/MMBtu) (grossed up for Company B Fuel)	-	-	90,449	90,449	90,449	90,449	90,449	90,449
Transco 85 to Company B Reservation Charge ($/MMBtu)	$ -	$ -	$ 0.240	$ 0.240	$ 0.240	$ 0.240	$ 0.240	$ 0.240
Capacity Addition 2								
MDQ (MMBtu/day)	[redacted]							
Reservation Charge ($/MMBtu)								
MDQ on Transco 85 to Company B ($/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)	$ -	$ -	$ -	$ 0.246	$ 0.246	$ 0.246	$ 0.246	$ 0.246
Capacity Addition 3								
MDQ (MMBtu/day)	-	-	-	-	175,000	175,000	175,000	175,000
Reservation Charge ($/MMBtu)	[redacted]							
MDQ on Transco 85 to Company B ($/MMBtu) (grossed up for Company B Fuel)	-	-	-	-	180,897	180,897	180,897	180,897
Transco 85 to Company B Reservation Charge ($/MMBtu)	$ -	$ -	$ -	$ -	$ 0.252	$ 0.252	$ 0.252	$ 0.252
Capacity Addition 4								
MDQ (MMBtu/day)	-	-	-	-	-	87,500	87,500	87,500
Reservation Charge ($/MMBtu)	[redacted]							
MDQ on Transco 85 to Company B ($/MMBtu) (grossed up for Company B Fuel)	-	-	-	-	-	90,449	90,449	90,449
Transco 85 to Company B Reservation Charge ($/MMBtu)	$ -	$ -	$ -	$ -	$ -	$ 0.258	$ 0.258	$ 0.258
Capacity Addition 5								
MDQ (MMBtu/day)	-	-	-	-	-	-	175,000	175,000
Reservation Charge ($/MMBtu)	[redacted]							
MDQ on Transco 85 to Company B ($/MMBtu) (grossed up for Company B Fuel)	-	-	-	-	-	-	180,897	180,897
Transco 85 to Company B Reservation Charge ($/MMBtu)	$ -	$ -	$ -	$ -	$ -	$ -	$ 0.265	$ 0.265
Capacity Addition 6								
MDQ (MMBtu/day)	-	-	-	-	-	-	-	175,000
Reservation Charge ($/MMBtu)	[redacted]							
MDQ on Transco 85 to Company B ($/MMBtu) (grossed up for Company B Fuel)	-	-	-	-	-	-	-	180,897
Transco 85 to Company B Reservation Charge ($/MMBtu)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 0.271
Annual Cost of Reservation Charges	[redacted]							

1/ 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.

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

ATTACHMENT I:

Project Demand Charges Incurred with Company B Offer

Annual Cost Escalator 2.50%
Company B Fuel Rate [redacted]
Transco 85 to Company B Fuel Rate 0.30%

Year	2027	2028	2029	2030	2031	2032	2033
Company B Proposed Rate - Escalated at 2.5% per year 1/	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Rate for Potential Pipeline from Transco 85 to Company B - Escalated at 2.5% per year 2/	$ 0.278	$ 0.285	$ 0.292	$ 0.299	$ 0.307	$ 0.315	$ 0.322
FPL Demand (MMBtu/day)	1,187,500	1,187,500	1,187,500	1,187,500	1,187,500	1,187,500	1,187,500
Company B Base Proposal							
Company B MDQ (MMBtu/day)	400,000	400,000	400,000	400,000	400,000	400,000	400,000
Company B Res. Fee ($/MMBtu)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
MDQ on Transco 85 to Company B ($/MMBtu) (grossed up for Company B Fuel)	413,479	413,479	413,479	413,479	413,479	413,479	413,479
Transco 85 to Company B Reservation Charge ($/MMBtu)	$ 0.200	$ 0.200	$ 0.200	$ 0.200	$ 0.200	$ 0.200	$ 0.200
Capacity Addition 1							
MDQ (MMBtu/day)	87,500	87,500	87,500	87,500	87,500	87,500	87,500
Reservation Charge ($/MMBtu)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
MDQ on Transco 85 to Company B ($/MMBtu) (grossed up for Company B Fuel)	90,449	90,449	90,449	90,449	90,449	90,449	90,449
Transco 85 to Company B Reservation Charge ($/MMBtu)	$ 0.240	$ 0.240	$ 0.240	$ 0.240	$ 0.240	$ 0.240	$ 0.240
Capacity Addition 2							
MDQ (MMBtu/day)	87,500	87,500	87,500	87,500	87,500	87,500	87,500
Reservation Charge ($/MMBtu)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
MDQ on Transco 85 to Company B ($/MMBtu) (grossed up for Company B Fuel)	90,449	90,449	90,449	90,449	90,449	90,449	90,449
Transco 85 to Company B Reservation Charge ($/MMBtu)	$ 0.246	$ 0.246	$ 0.246	$ 0.246	$ 0.246	$ 0.246	$ 0.246
Capacity Addition 3							
MDQ (MMBtu/day)	175,000	175,000	175,000	175,000	175,000	175,000	175,000
Reservation Charge ($/MMBtu)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
MDQ on Transco 85 to Company B ($/MMBtu) (grossed up for Company B Fuel)	180,897	180,897	180,897	180,897	180,897	180,897	180,897
Transco 85 to Company B Reservation Charge ($/MMBtu)	$ 0.252	$ 0.252	$ 0.252	$ 0.252	$ 0.252	$ 0.252	$ 0.252
Capacity Addition 4							
MDQ (MMBtu/day)	87,500	87,500	87,500	87,500	87,500	87,500	87,500
Reservation Charge ($/MMBtu)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
MDQ on Transco 85 to Company B ($/MMBtu) (grossed up for Company B Fuel)	90,449	90,449	90,449	90,449	90,449	90,449	90,449
Transco 85 to Company B Reservation Charge ($/MMBtu)	$ 0.258	$ 0.258	$ 0.258	$ 0.258	$ 0.258	$ 0.258	$ 0.258
Capacity Addition 5							
MDQ (MMBtu/day)	175,000	175,000	175,000	175,000	175,000	175,000	175,000
Reservation Charge ($/MMBtu)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
MDQ on Transco 85 to Company B ($/MMBtu) (grossed up for Company B Fuel)	180,897	180,897	180,897	180,897	180,897	180,897	180,897
Transco 85 to Company B Reservation Charge ($/MMBtu)	$ 0.265	$ 0.265	$ 0.265	$ 0.265	$ 0.265	$ 0.265	$ 0.265
Capacity Addition 6							
MDQ (MMBtu/day)	175,000	175,000	175,000	175,000	175,000	175,000	175,000
Reservation Charge ($/MMBtu)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
MDQ on Transco 85 to Company B ($/MMBtu) (grossed up for Company B Fuel)	180,897	180,897	180,897	180,897	180,897	180,897	180,897
Transco 85 to Company B Reservation Charge ($/MMBtu)	$ 0.271	$ 0.271	$ 0.271	$ 0.271	$ 0.271	$ 0.271	$ 0.271
Annual Cost of Reservation Charges	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

1/ 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.

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

ATTACHMENT I:

Project Demand Charges Incurred with Company B Offer

Annual Cost Escalator	**2.50%**
Company B Fuel Rate	[redacted]
Transco 85 to Company B Fuel Rate	**0.30%**

Year	2034	2035	2036	2037	2038	2039	2040	2041
Company B Proposed Rate - Escalated at 2.5% per year 1/	[redacted]							
Rate for Potential Pipeline from Transco 85 to Company B - Escalated at 2.5% per year 2/	$ 0.330	$ 0.339	$ 0.347	$ 0.356	$ 0.365	$ 0.374	$ 0.383	$ 0.393
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	1,187,500
Company B Base Proposal								
Company B MDQ (MMBtu/day)	400,000	400,000	400,000	400,000	400,000	400,000	400,000	400,000
Company B Res. Fee ($/MMBtu)	[redacted]							
MDQ on Transco 85 to Company B ($/MMBtu) (grossed up for Company B Fuel)	413,479	413,479	413,479	413,479	413,479	413,479	413,479	413,479
Transco 85 to Company B Reservation Charge ($/MMBtu)	$ 0.200	$ 0.200	$ 0.200	$ 0.200	$ 0.200	$ 0.200	$ 0.200	$ 0.200
Capacity Addition 1								
MDQ (MMBtu/day)	87,500	87,500	87,500	87,500	87,500	87,500	87,500	87,500
Reservation Charge ($/MMBtu)	[redacted]							
MDQ on Transco 85 to Company B ($/MMBtu) (grossed up for Company B Fuel)	90,449	90,449	90,449	90,449	90,449	90,449	90,449	90,449
Transco 85 to Company B Reservation Charge ($/MMBtu)	$ 0.240	$ 0.240	$ 0.240	$ 0.240	$ 0.240	$ 0.240	$ 0.240	$ 0.240
Capacity Addition 2								
MDQ (MMBtu/day)	87,500	87,500	87,500	87,500	87,500	87,500	87,500	87,500
Reservation Charge ($/MMBtu)	[redacted]							
MDQ on Transco 85 to Company B ($/MMBtu) (grossed up for Company B Fuel)	90,449	90,449	90,449	90,449	90,449	90,449	90,449	90,449
Transco 85 to Company B Reservation Charge ($/MMBtu)	$ 0.246	$ 0.246	$ 0.246	$ 0.246	$ 0.246	$ 0.246	$ 0.246	$ 0.246
Capacity Addition 3								
MDQ (MMBtu/day)	175,000	175,000	175,000	175,000	175,000	175,000	175,000	175,000
Reservation Charge ($/MMBtu)	[redacted]							
MDQ on Transco 85 to Company B ($/MMBtu) (grossed up for Company B Fuel)	180,897	180,897	180,897	180,897	180,897	180,897	180,897	180,897
Transco 85 to Company B Reservation Charge ($/MMBtu)	$ 0.252	$ 0.252	$ 0.252	$ 0.252	$ 0.252	$ 0.252	$ 0.252	$ 0.252
Capacity Addition 4								
MDQ (MMBtu/day)	87,500	87,500	87,500	87,500	87,500	87,500	87,500	87,500
Reservation Charge ($/MMBtu)	[redacted]							
MDQ on Transco 85 to Company B ($/MMBtu) (grossed up for Company B Fuel)	90,449	90,449	90,449	90,449	90,449	90,449	90,449	90,449
Transco 85 to Company B Reservation Charge ($/MMBtu)	$ 0.258	$ 0.258	$ 0.258	$ 0.258	$ 0.258	$ 0.258	$ 0.258	$ 0.258
Capacity Addition 5								
MDQ (MMBtu/day)	175,000	175,000	175,000	175,000	175,000	175,000	175,000	175,000
Reservation Charge ($/MMBtu)	[redacted]							
MDQ on Transco 85 to Company B ($/MMBtu) (grossed up for Company B Fuel)	180,897	180,897	180,897	180,897	180,897	180,897	180,897	180,897
Transco 85 to Company B Reservation Charge ($/MMBtu)	$ 0.265	$ 0.265	$ 0.265	$ 0.265	$ 0.265	$ 0.265	$ 0.265	$ 0.265
Capacity Addition 6								
MDQ (MMBtu/day)	175,000	175,000	175,000	175,000	175,000	175,000	175,000	175,000
Reservation Charge ($/MMBtu)	[redacted]							
MDQ on Transco 85 to Company B ($/MMBtu) (grossed up for Company B Fuel)	180,897	180,897	180,897	180,897	180,897	180,897	180,897	180,897
Transco 85 to Company B Reservation Charge ($/MMBtu)	$ 0.271	$ 0.271	$ 0.271	$ 0.271	$ 0.271	$ 0.271	$ 0.271	$ 0.271
Annual Cost of Reservation Charges	[redacted]							

1/ 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.

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

ATTACHMENT I:

Project Demand Charges Incurred with Company B Offer

Annual Cost Escalator 2.50%
Company B Fuel Rate [redacted]
Transco 85 to Company B Fuel Rate 0.30%

Year	2042	2043	2044	2045	2046	2047	2048	2049
Company B Proposed Rate - Escalated at 2.5% per year 1/	[redacted]							
Rate for Potential Pipeline from Transco 85 to Company B - Escalated at 2.5% per year 2/	$ 0.403	$ 0.413	$ 0.423	$ 0.434	$ 0.444	$ 0.456	$ 0.467	$ 0.479
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	1,187,500
Company B Base Proposal								
Company B MDQ (MMBtu/day)	400,000	400,000	400,000	400,000	400,000	400,000	400,000	400,000
Company B Res. Fee ($/MMBtu)	[redacted]							
MDQ on Transco 85 to Company B ($/MMBtu) (grossed up for Company B Fuel)	413,479	413,479	413,479	413,479	413,479	413,479	413,479	413,479
Transco 85 to Company B Reservation Charge ($/MMBtu)	$ 0.200	$ 0.200	$ 0.200	$ 0.200	$ 0.200	$ 0.200	$ 0.200	$ 0.200
Capacity Addition 1								
MDQ (MMBtu/day)	87,500	87,500	87,500	87,500	87,500	87,500	87,500	87,500
Reservation Charge ($/MMBtu)	[redacted]							
MDQ on Transco 85 to Company B ($/MMBtu) (grossed up for Company B Fuel)	90,449	90,449	90,449	90,449	90,449	90,449	90,449	90,449
Transco 85 to Company B Reservation Charge ($/MMBtu)	$ 0.240	$ 0.240	$ 0.240	$ 0.240	$ 0.240	$ 0.240	$ 0.240	$ 0.240
Capacity Addition 2								
MDQ (MMBtu/day)	87,500	87,500	87,500	87,500	87,500	87,500	87,500	87,500
Reservation Charge ($/MMBtu)	[redacted]							
MDQ on Transco 85 to Company B ($/MMBtu) (grossed up for Company B Fuel)	90,449	90,449	90,449	90,449	90,449	90,449	90,449	90,449
Transco 85 to Company B Reservation Charge ($/MMBtu)	$ 0.246	$ 0.246	$ 0.246	$ 0.246	$ 0.246	$ 0.246	$ 0.246	$ 0.246
Capacity Addition 3								
MDQ (MMBtu/day)	175,000	175,000	175,000	175,000	175,000	175,000	175,000	175,000
Reservation Charge ($/MMBtu)	[redacted]							
MDQ on Transco 85 to Company B ($/MMBtu) (grossed up for Company B Fuel)	180,897	180,897	180,897	180,897	180,897	180,897	180,897	180,897
Transco 85 to Company B Reservation Charge ($/MMBtu)	$ 0.252	$ 0.252	$ 0.252	$ 0.252	$ 0.252	$ 0.252	$ 0.252	$ 0.252
Capacity Addition 4								
MDQ (MMBtu/day)	87,500	87,500	87,500	87,500	87,500	87,500	87,500	87,500
Reservation Charge ($/MMBtu)	[redacted]							
MDQ on Transco 85 to Company B ($/MMBtu) (grossed up for Company B Fuel)	90,449	90,449	90,449	90,449	90,449	90,449	90,449	90,449
Transco 85 to Company B Reservation Charge ($/MMBtu)	$ 0.258	$ 0.258	$ 0.258	$ 0.258	$ 0.258	$ 0.258	$ 0.258	$ 0.258
Capacity Addition 5								
MDQ (MMBtu/day)	175,000	175,000	175,000	175,000	175,000	175,000	175,000	175,000
Reservation Charge ($/MMBtu)	[redacted]							
MDQ on Transco 85 to Company B ($/MMBtu) (grossed up for Company B Fuel)	180,897	180,897	180,897	180,897	180,897	180,897	180,897	180,897
Transco 85 to Company B Reservation Charge ($/MMBtu)	$ 0.265	$ 0.265	$ 0.265	$ 0.265	$ 0.265	$ 0.265	$ 0.265	$ 0.265
Capacity Addition 6								
MDQ (MMBtu/day)	175,000	175,000	175,000	175,000	175,000	175,000	175,000	175,000
Reservation Charge ($/MMBtu)	[redacted]							
MDQ on Transco 85 to Company B ($/MMBtu) (grossed up for Company B Fuel)	180,897	180,897	180,897	180,897	180,897	180,897	180,897	180,897
Transco 85 to Company B Reservation Charge ($/MMBtu)	$ 0.271	$ 0.271	$ 0.271	$ 0.271	$ 0.271	$ 0.271	$ 0.271	$ 0.271
Annual Cost of Reservation Charges	[redacted]							

1/ 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.

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

ATTACHMENT I:

Project Demand Charges Incurred with Company B Offer

Annual Cost Escalator 2.50%
Company B Fuel Rate [redacted]
Transco 85 to Company B Fuel Rate 0.30%

Year	2050	2051	2052	2053
Company B Proposed Rate - Escalated at 2.5% per year 1/	[redacted]	[redacted]	[redacted]	[redacted]
Rate for Potential Pipeline from Transco 85 to Company B - Escalated at 2.5% per year 2/	$ 0.491	$ 0.503	$ 0.515	$ 0.528
FPL Demand (MMBtu/day)	1,187,500	1,187,500	1,187,500	1,187,500
Company B Base Proposal				
Company B MDQ (MMBtu/day)	400,000	400,000	400,000	400,000
Company B Res. Fee ($/MMBtu)	[redacted]	[redacted]	[redacted]	[redacted]
MDQ on Transco 85 to Company B ($/MMBtu) (grossed up for Company B Fuel)	413,479	413,479	413,479	413,479
Transco 85 to Company B Reservation Charge ($/MMBtu)	$ 0.200	$ 0.200	$ 0.200	$ 0.200
Capacity Addition 1				
MDQ (MMBtu/day)	87,500	87,500	87,500	87,500
Reservation Charge ($/MMBtu)	[redacted]	[redacted]	[redacted]	[redacted]
MDQ on Transco 85 to Company B ($/MMBtu) (grossed up for Company B Fuel)	90,449	90,449	90,449	90,449
Transco 85 to Company B Reservation Charge ($/MMBtu)	$ 0.240	$ 0.240	$ 0.240	$ 0.240
Capacity Addition 2				
MDQ (MMBtu/day)	87,500	87,500	87,500	87,500
Reservation Charge ($/MMBtu)	[redacted]	[redacted]	[redacted]	[redacted]
MDQ on Transco 85 to Company B ($/MMBtu) (grossed up for Company B Fuel)	90,449	90,449	90,449	90,449
Transco 85 to Company B Reservation Charge ($/MMBtu)	$ 0.246	$ 0.246	$ 0.246	$ 0.246
Capacity Addition 3				
MDQ (MMBtu/day)	175,000	175,000	175,000	175,000
Reservation Charge ($/MMBtu)	[redacted]	[redacted]	[redacted]	[redacted]
MDQ on Transco 85 to Company B ($/MMBtu) (grossed up for Company B Fuel)	180,897	180,897	180,897	180,897
Transco 85 to Company B Reservation Charge ($/MMBtu)	$ 0.252	$ 0.252	$ 0.252	$ 0.252
Capacity Addition 4				
MDQ (MMBtu/day)	87,500	87,500	87,500	87,500
Reservation Charge ($/MMBtu)	[redacted]	[redacted]	[redacted]	[redacted]
MDQ on Transco 85 to Company B ($/MMBtu) (grossed up for Company B Fuel)	90,449	90,449	90,449	90,449
Transco 85 to Company B Reservation Charge ($/MMBtu)	$ 0.258	$ 0.258	$ 0.258	$ 0.258
Capacity Addition 5				
MDQ (MMBtu/day)	175,000	175,000	175,000	175,000
Reservation Charge ($/MMBtu)	[redacted]	[redacted]	[redacted]	[redacted]
MDQ on Transco 85 to Company B ($/MMBtu) (grossed up for Company B Fuel)	180,897	180,897	180,897	180,897
Transco 85 to Company B Reservation Charge ($/MMBtu)	$ 0.265	$ 0.265	$ 0.265	$ 0.265
Capacity Addition 6				
MDQ (MMBtu/day)	175,000	175,000	175,000	175,000
Reservation Charge ($/MMBtu)	[redacted]	[redacted]	[redacted]	[redacted]
MDQ on Transco 85 to Company B ($/MMBtu) (grossed up for Company B Fuel)	180,897	180,897	180,897	180,897
Transco 85 to Company B Reservation Charge ($/MMBtu)	$ 0.271	$ 0.271	$ 0.271	$ 0.271
Annual Cost of Reservation Charges	[redacted]	[redacted]	[redacted]	[redacted]

1/ 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.

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

ATTACHMENT II:

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

		Fuel Gas Retained on Company B System					Fuel Gas Retained on Lateral from Transco 85 to Company B				Calculated Cost of Fuel Gas			
Year	FPL Natural Gas Demand Served (MMBtu/day)	Proposed Contract MDQ on Company B (MMBtu/day)	Average Load Factor for New Capacity (%) 1/	Annual Throughput on Company B (MMBtu)	Company B Fuel Rate %	Company B Fuel Gas Retained (MMBtu)	Contract MDQ Lateral Extension (MMBtu/day)	Annual Throughput on Lateral (MMBtu)	Projected Lateral Fuel Rate % 2/	Lateral Fuel Gas Retained (MMBtu)	Henry Hub Cost of Gas ($/MMBtu) 3/	Basis to Transco Zone 4 ($/MMBtu) 4/	Unit Cost of Fuel Gas ($/MMBtu)	Annual Cost of Fuel Gas $
Column	1	2	3	4	5	6	7	8	9	10	11	12	13	14
Source	FPL Load Forecast	Col 1	See Footnote	See Footnote	[redacted]	[Col 4 / (1- Col 5)] - Col 4	Col 2 / (1 - Col 5)	Col 7 * days in year * Col 3	See Footnote 2/	[Col 8 / (1- Col 9)] - Col 8	See Footnote 3/	See Footnote 4/	Col 11 + Col 12	Col 13 * (Col 6 + Col 10)
2012	50,000	50,000	0%	-	[redacted]			-	0.30%	-	$ 8.130	$ 0.0525	$ 8.1823	[redacted]
2013	400,000	400,000	54%	32,916,000				34,025,222	0.30%	102,383	$ 8.293	$ 0.0525	$ 8.3453	
2014	400,000	400,000	59%	85,422,300				88,300,910	0.30%	265,700	$ 8.692	$ 0.0525	$ 8.7449	
2015	400,000	400,000	72%	104,757,800				108,287,988	0.30%	325,841	$ 9.192	$ 0.0525	$ 9.2445	
2016	400,000	400,000	76%	111,114,000				114,858,383	0.30%	345,612	$ 9.692	$ 0.0525	$ 9.7440	
2017	400,000	400,000	78%	114,002,300				117,844,015	0.30%	354,596	$ 10.291	$ 0.0525	$ 10.3435	
2018	400,000	400,000	79%	115,486,300				119,378,024	0.30%	359,212	$ 11.090	$ 0.0525	$ 11.1428	
2019	400,000	400,000	78%	114,415,400				118,271,036	0.30%	355,881	$ 12.089	$ 0.0525	$ 12.1420	
2020	400,000	400,000	76%	111,570,500				115,330,267	0.30%	347,032	$ 12.742	$ 0.0525	$ 12.7942	
2021	487,500	487,500	75%	133,453,125				137,950,305	0.30%	415,096	$ 12.997	$ 0.0525	$ 13.0490	
2022	575,000	575,000	75%	157,406,250				162,710,616	0.30%	489,601	$ 13.256	$ 0.0525	$ 13.3089	
2023	750,000	750,000	75%	205,312,500				212,231,238	0.30%	638,610	$ 13.522	$ 0.0525	$ 13.5740	
2024	837,500	837,500	75%	229,893,750				237,640,841	0.30%	715,068	$ 13.792	$ 0.0525	$ 13.8444	
2025	1,012,500	1,012,500	75%	277,171,875				286,512,172	0.30%	862,123	$ 14.068	$ 0.0525	$ 14.1202	
2026	1,187,500	1,187,500	75%	325,078,125				336,032,794	0.30%	1,011,132	$ 14.349	$ 0.0525	$ 14.4015	
2027	1,187,500	1,187,500	75%	325,078,125				336,032,794	0.30%	1,011,132	$ 14.636	$ 0.0525	$ 14.6885	
2028	1,187,500	1,187,500	75%	325,968,750				336,953,432	0.30%	1,013,902	$ 14.929	$ 0.0525	$ 14.9812	
2029	1,187,500	1,187,500	75%	325,078,125				336,032,794	0.30%	1,011,132	$ 15.227	$ 0.0525	$ 15.2797	
2030	1,187,500	1,187,500	75%	325,078,125				336,032,794	0.30%	1,011,132	$ 15.532	$ 0.0525	$ 15.5842	
2031	1,187,500	1,187,500	75%	325,078,125				336,032,794	0.30%	1,011,132	$ 15.842	$ 0.0525	$ 15.8948	
2032	1,187,500	1,187,500	75%	325,968,750				336,953,432	0.30%	1,013,902	$ 16.159	$ 0.0525	$ 16.2116	
2033	1,187,500	1,187,500	75%	325,078,125				336,032,794	0.30%	1,011,132	$ 16.482	$ 0.0525	$ 16.5348	
2034	1,187,500	1,187,500	75%	325,078,125				336,032,794	0.30%	1,011,132	$ 16.812	$ 0.0525	$ 16.8644	
2035	1,187,500	1,187,500	75%	325,078,125				336,032,794	0.30%	1,011,132	$ 17.148	$ 0.0525	$ 17.2006	
2036	1,187,500	1,187,500	75%	325,968,750				336,953,432	0.30%	1,013,902	$ 17.491	$ 0.0525	$ 17.5435	
2037	1,187,500	1,187,500	75%	325,078,125				336,032,794	0.30%	1,011,132	$ 17.841	$ 0.0525	$ 17.8933	
2038	1,187,500	1,187,500	75%	325,078,125				336,032,794	0.30%	1,011,132	$ 18.198	$ 0.0525	$ 18.2501	
2039	1,187,500	1,187,500	75%	325,078,125				336,032,794	0.30%	1,011,132	$ 18.561	$ 0.0525	$ 18.6140	
2040	1,187,500	1,187,500	75%	325,968,750				336,953,432	0.30%	1,013,902	$ 18.933	$ 0.0525	$ 18.9852	
2041	1,187,500	1,187,500	75%	325,078,125				336,032,794	0.30%	1,011,132	$ 19.311	$ 0.0525	$ 19.3638	
2042	1,187,500	1,187,500	75%	325,078,125				336,032,794	0.30%	1,011,132	$ 19.697	$ 0.0525	$ 19.7500	
2043	1,187,500	1,187,500	75%	325,078,125				336,032,794	0.30%	1,011,132	$ 20.091	$ 0.0525	$ 20.1439	
2044	1,187,500	1,187,500	75%	325,968,750				336,953,432	0.30%	1,013,902	$ 20.493	$ 0.0525	$ 20.5457	
2045	1,187,500	1,187,500	75%	325,078,125				336,032,794	0.30%	1,011,132	$ 20.903	$ 0.0525	$ 20.9555	
2046	1,187,500	1,187,500	75%	325,078,125				336,032,794	0.30%	1,011,132	$ 21.321	$ 0.0525	$ 21.3735	
2047	1,187,500	1,187,500	75%	325,078,125				336,032,794	0.30%	1,011,132	$ 21.747	$ 0.0525	$ 21.7999	
2048	1,187,500	1,187,500	75%	325,968,750				336,953,432	0.30%	1,013,902	$ 22.182	$ 0.0525	$ 22.2348	
2049	1,187,500	1,187,500	75%	325,078,125				336,032,794	0.30%	1,011,132	$ 22.626	$ 0.0525	$ 22.6784	
2050	1,187,500	1,187,500	75%	325,078,125				336,032,794	0.30%	1,011,132	$ 23.078	$ 0.0525	$ 23.1308	
2051	1,187,500	1,187,500	75%	325,078,125				336,032,794	0.30%	1,011,132	$ 23.540	$ 0.0525	$ 23.5923	
2052	1,187,500	1,187,500	75%	325,968,750				336,953,432	0.30%	1,013,902	$ 24.011	$ 0.0525	$ 24.0631	
2053	1,187,500	1,187,500	75%	325,078,125				336,032,794	0.30%	1,011,132	$ 24.491	$ 0.0525	$ 24.5432	

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

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

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

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

ATTACHMENT III A:

Total Annual Revenue Requirements for Florida EnergySecure Line Project

	RR to offset Project Investment		Incremental Capacity Required			Value of Incremental Capacity Purchases: Case A - Current Market			Value of Incremental Capacity Purchases: Case B - FGT Phase III Max Rate			Value of Incremental Capacity Purchases: Case C - No Spot Market Capacity Value		
Year	Cost of On-Site Compression at CCEC Facility ($)	Annual Florida EnergySecure Line Revenue Requirements ($)	Peak Day Demand Served by Incremental Capacity (MMBtu/day)	Florida EnergySecure Line Project Capacity (MMBtu/day)	Incremental Capacity to be Purchased in Spot Market (MMBtu/day)	Unit Cost of Spot Market Capacity ($/MMBtu)	Cost of Spot Market Capacity ($)	Total Cost of Energy Secure Line Project ($)	Unit Cost of Spot Market Capacity ($/MMBtu)	Cost of Spot Market Capacity ($)	Total Cost of Energy Secure Line Project ($)	Unit Cost of Spot Market Capacity ($/MMBtu)	Cost of Spot Market Capacity ($)	Total Cost of Energy Secure Line Project ($)
Column	1	2	3	4	5	6	7	8	9	10	11	12	13	14
Source	FPL Engineering	FPL Revenue Requirements Analysis 1/	See Footnote 2/	See Footnote 3/	Column 3 - Column 4	See Footnote 4/	Col 5 * Col 6 * days	Col 1 + Col 2 + Col 7	See Footnote 5/	Col 5 * Col 9 * days	Col 1 + Col 2 + Col 10	See Footnote 6/	Col 5 * Col 12 * days	Col 1 + Col 2 + Col 13
Sept 1, 2012 - Dec 1, 2012	$25,000,000	$0	-	0	0	$ 0.4614	$0	$25,000,000	$ 1.5857	$0	$25,000,000	$ -	$0	$25,000,000
Dec 1, 2012 - Jan 1, 2013	$0	$0	30,000	0	30,000	$ 0.4614	$429,102	$429,102	$ 1.5857	$1,474,701	$1,474,701	$ -	$0	$0
Jan 1, 2013 - March 1, 2013	$0	$0	30,000	0	30,000	$ 0.4614	$816,678	$816,678	$ 1.5857	$2,806,689	$2,806,689	$ -	$0	$0
March 1, 2013 - Sept 1, 2013	$0	$0	50,000	0	50,000	$ 0.4614	$4,244,880	$4,244,880	$ 1.5857	$14,588,440	$14,588,440	$ -	$0	$0
Sept 1, 2013 - Dec 1, 2013	$0	$0	200,000	0	200,000	$ 0.4614	$8,397,480	$8,397,480	$ 1.5857	$28,859,740	$28,859,740	$ -	$0	$0
Dec 1, 2013 - Jan 1, 2014	$0	$0	230,000	0	230,000	$ 0.4614	$3,289,782	$3,289,782	$ 1.5857	$11,306,041	$11,306,041	$ -	$0	$0
Jan 1, 2014 - March 1, 2014	$0	$46,613,978	230,000	596,718	0	$ 0.4614	$0	$46,613,978	$ 1.5857	$0	$46,613,978	$ -	$0	$46,613,978
March 1, 2014 - June 1, 2014	$0	$72,686,202	250,000	596,718	0	$ 0.4614	$0	$72,686,202	$ 1.5857	$0	$72,686,202	$ -	$0	$72,686,202
June 1 2014 - Jan 1 2015	$0	$169,074,427	400,000	596,718	0	$ 0.4614	$0	$169,074,427	$ 1.5857	$0	$169,074,427	$ -	$0	$169,074,427
2015	$0	$278,493,512	400,000	596,718	0	$ 0.4729	$0	$278,493,512	$ 1.5857	$0	$278,493,512	$ -	$0	$278,493,512
2016	$0	$267,187,914	400,000	596,718	0	$ 0.4848	$0	$267,187,914	$ 1.5857	$0	$267,187,914	$ -	$0	$267,187,914
2017	$0	$256,609,825	400,000	596,718	0	$ 0.4969	$0	$256,609,825	$ 1.5857	$0	$256,609,825	$ -	$0	$256,609,825
2018	$0	$246,685,353	400,000	596,718	0	$ 0.5093	$0	$246,685,353	$ 1.5857	$0	$246,685,353	$ -	$0	$246,685,353
2019	$0	$237,347,420	400,000	596,718	0	$ 0.5220	$0	$237,347,420	$ 1.5857	$0	$237,347,420	$ -	$0	$237,347,420
2020	$0	$228,424,559	400,000	596,718	0	$ 0.5351	$0	$228,424,559	$ 1.5857	$0	$228,424,559	$ -	$0	$228,424,559
2021	$0	$219,638,646	487,500	596,718	0	$ 0.5485	$0	$219,638,646	$ 1.5857	$0	$219,638,646	$ -	$0	$219,638,646
2022	$0	$210,855,067	575,000	596,718	0	$ 0.5622	$0	$210,855,067	$ 1.5857	$0	$210,855,067	$ -	$0	$210,855,067
2023	$0	$223,950,971	750,000	800,000	0	$ 0.5762	$0	$223,950,971	$ 1.5857	$0	$223,950,971	$ -	$0	$223,950,971
2024	$0	$229,621,800	837,500	1,000,000	0	$ 0.5906	$0	$229,621,800	$ 1.5857	$0	$229,621,800	$ -	$0	$229,621,800
2025	$0	$272,442,660	1,012,500	1,250,000	0	$ 0.6054	$0	$272,442,660	$ 1.5857	$0	$272,442,660	$ -	$0	$272,442,660
2026	$0	$260,520,128	1,187,500	1,250,000	0	$ 0.6205	$0	$260,520,128	$ 1.5857	$0	$260,520,128	$ -	$0	$260,520,128
2027	$0	$248,431,383	1,187,500	1,250,000	0	$ 0.6360	$0	$248,431,383	$ 1.5857	$0	$248,431,383	$ -	$0	$248,431,383
2028	$0	$236,546,383	1,187,500	1,250,000	0	$ 0.6519	$0	$236,546,383	$ 1.5857	$0	$236,546,383	$ -	$0	$236,546,383
2029	$0	$226,038,819	1,187,500	1,250,000	0	$ 0.6682	$0	$226,038,819	$ 1.5857	$0	$226,038,819	$ -	$0	$226,038,819
2030	$0	$218,048,644	1,187,500	1,250,000	0	$ 0.6850	$0	$218,048,644	$ 1.5857	$0	$218,048,644	$ -	$0	$218,048,644
2031	$0	$211,315,829	1,187,500	1,250,000	0	$ 0.7021	$0	$211,315,829	$ 1.5857	$0	$211,315,829	$ -	$0	$211,315,829
2032	$0	$204,612,370	1,187,500	1,250,000	0	$ 0.7196	$0	$204,612,370	$ 1.5857	$0	$204,612,370	$ -	$0	$204,612,370
2033	$0	$197,884,875	1,187,500	1,250,000	0	$ 0.7376	$0	$197,884,875	$ 1.5857	$0	$197,884,875	$ -	$0	$197,884,875
2034	$0	$191,197,743	1,187,500	1,250,000	0	$ 0.7561	$0	$191,197,743	$ 1.5857	$0	$191,197,743	$ -	$0	$191,197,743
2035	$0	$184,516,658	1,187,500	1,250,000	0	$ 0.7750	$0	$184,516,658	$ 1.5857	$0	$184,516,658	$ -	$0	$184,516,658
2036	$0	$177,871,805	1,187,500	1,250,000	0	$ 0.7943	$0	$177,871,805	$ 1.5857	$0	$177,871,805	$ -	$0	$177,871,805
2037	$0	$171,188,230	1,187,500	1,250,000	0	$ 0.8142	$0	$171,188,230	$ 1.5857	$0	$171,188,230	$ -	$0	$171,188,230
2038	$0	$164,611,149	1,187,500	1,250,000	0	$ 0.8345	$0	$164,611,149	$ 1.5857	$0	$164,611,149	$ -	$0	$164,611,149
2039	$0	$158,275,795	1,187,500	1,250,000	0	$ 0.8554	$0	$158,275,795	$ 1.5857	$0	$158,275,795	$ -	$0	$158,275,795
2040	$0	$152,371,651	1,187,500	1,250,000	0	$ 0.8768	$0	$152,371,651	$ 1.5857	$0	$152,371,651	$ -	$0	$152,371,651
2041	$0	$146,968,757	1,187,500	1,250,000	0	$ 0.8987	$0	$146,968,757	$ 1.5857	$0	$146,968,757	$ -	$0	$146,968,757
2042	$0	$141,788,923	1,187,500	1,250,000	0	$ 0.9212	$0	$141,788,923	$ 1.5857	$0	$141,788,923	$ -	$0	$141,788,923
2043	$0	$136,614,736	1,187,500	1,250,000	0	$ 0.9442	$0	$136,614,736	$ 1.5857	$0	$136,614,736	$ -	$0	$136,614,736
2044	$0	$131,446,318	1,187,500	1,250,000	0	$ 0.9678	$0	$131,446,318	$ 1.5857	$0	$131,446,318	$ -	$0	$131,446,318
2045	$0	$126,283,794	1,187,500	1,250,000	0	$ 0.9920	$0	$126,283,794	$ 1.5857	$0	$126,283,794	$ -	$0	$126,283,794
2046	$0	$121,865,958	1,187,500	1,250,000	0	$ 1.0168	$0	$121,865,958	$ 1.5857	$0	$121,865,958	$ -	$0	$121,865,958
2047	$0	$117,454,275	1,187,500	1,250,000	0	$ 1.0422	$0	$117,454,275	$ 1.5857	$0	$117,454,275	$ -	$0	$117,454,275
2048	$0	$113,048,878	1,187,500	1,250,000	0	$ 1.0683	$0	$113,048,878	$ 1.5857	$0	$113,048,878	$ -	$0	$113,048,878
2049	$0	$108,649,904	1,187,500	1,250,000	0	$ 1.0950	$0	$108,649,904	$ 1.5857	$0	$108,649,904	$ -	$0	$108,649,904
2050	$0	$104,257,493	1,187,500	1,250,000	0	$ 1.1224	$0	$104,257,493	$ 1.5857	$0	$104,257,493	$ -	$0	$104,257,493
2051	$0	$99,630,311	1,187,500	1,250,000	0	$ 1.1504	$0	$99,630,311	$ 1.5857	$0	$99,630,311	$ -	$0	$99,630,311
2052	$0	$95,005,139	1,187,500	1,250,000	0	$ 1.1792	$0	$95,005,139	$ 1.5857	$0	$95,005,139	$ -	$0	$95,005,139
2053	$0	$90,382,030	1,187,500	1,250,000	0	$ 1.2087	$0	$90,382,030	$ 1.5857	$0	$90,382,030	$ -	$0	$90,382,030

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

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

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

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

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

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

ATTACHMENT III B:

Project Demand Charges Incurred with Company E Upstream Pipeline Project

Annual Cost Escalator **2.50%**

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

ATTACHMENT III B:

Project Demand Charges Incurred with Company E Upstream Pipeline Project

Annual Cost Escalator **2.50%**

Year	2019	2020	2021	2022	2023	2024
Company E Proposed Rate - Escalated	[redacted]					
FPL Demand (MMBtu/day)	400,000	400,000	487,500	575,000	750,000	837,500
Projected EnergySecure Line Fuel Retention (%)	0.55%	0.55%	0.55%	0.93%	0.93%	1.07%
MDQ Required on Upstream P/L Project (MMBtu/day)	402,212	402,212	490,196	580,398	757,040	846,558
Company E Pipeline Proposal						
MDQ (MMBtu/day)	600,000	600,000	600,000	600,000	600,000	600,000
Upstream Pipeline Project Res. Fee ($/MMBtu)	[redacted]					
Capacity Addition 1						
MDQ (MMBtu/day)	-	-	-		157,040	157,040
Reservation Charge ($/MMBtu)	[redacted]					
Capacity Addition 2						
MDQ (MMBtu/day)	-	-	-	-		89,518
Reservation Charge ($/MMBtu)	[redacted]					
Capacity Addition 3						
MDQ (MMBtu/day)	-	-	-	-	-	
Reservation Charge ($/MMBtu)	[redacted]					
Capacity Addition 4						
MDQ (MMBtu/day)	-	-	-	-	-	-
Reservation Charge ($/MMBtu)	[redacted]					
Annual Cost of Reservation Charges	[redacted]					

ATTACHMENT III B:

Project Demand Charges Incurred with Company E Upstream Pipeline Project

Annual Cost Escalator **2.50%**

Year	2025	2026	2027	2028	2029	2030
Company E Proposed Rate - Escalated	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
FPL Demand (MMBtu/day)	1,012,500	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)	1,029,905	1,207,914	1,207,914	1,207,914	1,207,914	1,207,914
Company E Pipeline Proposal						
MDQ (MMBtu/day)	600,000	600,000	600,000	600,000	600,000	600,000
Upstream Pipeline Project Res. Fee ($/MMBtu)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Capacity Addition 1						
MDQ (MMBtu/day)	157,040	157,040	157,040	157,040	157,040	157,040
Reservation Charge ($/MMBtu)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Capacity Addition 2						
MDQ (MMBtu/day)	89,518	89,518	89,518	89,518	89,518	89,518
Reservation Charge ($/MMBtu)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Capacity Addition 3						
MDQ (MMBtu/day)	183,347	183,347	183,347	183,347	183,347	183,347
Reservation Charge ($/MMBtu)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Capacity Addition 4						
MDQ (MMBtu/day)		178,008	178,008	178,008	178,008	178,008
Reservation Charge ($/MMBtu)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Annual Cost of Reservation Charges	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

ATTACHMENT III B:

Project Demand Charges Incurred with Company E Upstream Pipeline Project

Annual Cost Escalator **2.50%**

Year	2031	2032	2033	2034	2035	2036
Company E Proposed Rate - Escalated	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
FPL Demand (MMBtu/day)	1,187,500	1,187,500	1,187,500	1,187,500	1,187,500	1,187,500
Projected EnergySecure Line Fuel Retention (%)	1.69%	1.69%	1.69%	1.69%	1.69%	1.69%
MDQ Required on Upstream P/L Project (MMBtu/day)	1,207,914	1,207,914	1,207,914	1,207,914	1,207,914	1,207,914
Company E Pipeline Proposal						
MDQ (MMBtu/day)	600,000	600,000	600,000	600,000	600,000	600,000
Upstream Pipeline Project Res. Fee ($/MMBtu)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Capacity Addition 1						
MDQ (MMBtu/day)	157,040	157,040	157,040	157,040	157,040	157,040
Reservation Charge ($/MMBtu)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Capacity Addition 2						
MDQ (MMBtu/day)	89,518	89,518	89,518	89,518	89,518	89,518
Reservation Charge ($/MMBtu)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Capacity Addition 3						
MDQ (MMBtu/day)	183,347	183,347	183,347	183,347	183,347	183,347
Reservation Charge ($/MMBtu)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Capacity Addition 4						
MDQ (MMBtu/day)	178,008	178,008	178,008	178,008	178,008	178,008
Reservation Charge ($/MMBtu)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Annual Cost of Reservation Charges	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

ATTACHMENT III B:

Project Demand Charges Incurred with Company E Upstream Pipeline Project

Annual Cost Escalator **2.50%**

Year	2037	2038	2039	2040	2041	2042
Company E Proposed Rate - Escalated	[redacted]					
FPL Demand (MMBtu/day)	1,187,500	1,187,500	1,187,500	1,187,500	1,187,500	1,187,500
Projected EnergySecure Line Fuel Retention (%)	1.69%	1.69%	1.69%	1.69%	1.69%	1.69%
MDQ Required on Upstream P/L Project (MMBtu/day)	1,207,914	1,207,914	1,207,914	1,207,914	1,207,914	1,207,914
Company E Pipeline Proposal						
MDQ (MMBtu/day)	600,000	600,000	600,000	600,000	600,000	600,000
Upstream Pipeline Project Res. Fee ($/MMBtu)	[redacted]					
Capacity Addition 1						
MDQ (MMBtu/day)	157,040	157,040	157,040	157,040	157,040	157,040
Reservation Charge ($/MMBtu)	[redacted]					
Capacity Addition 2						
MDQ (MMBtu/day)	89,518	89,518	89,518	89,518	89,518	89,518
Reservation Charge ($/MMBtu)	[redacted]					
Capacity Addition 3						
MDQ (MMBtu/day)	183,347	183,347	183,347	183,347	183,347	183,347
Reservation Charge ($/MMBtu)	[redacted]					
Capacity Addition 4						
MDQ (MMBtu/day)	178,008	178,008	178,008	178,008	178,008	178,008
Reservation Charge ($/MMBtu)	[redacted]					
Annual Cost of Reservation Charges	[redacted]					

ATTACHMENT III B:

Project Demand Charges Incurred with Company E Upstream Pipeline Project

Annual Cost Escalator **2.50%**

Year	2043	2044	2045	2046	2047	2048
Company E Proposed Rate - Escalated	[redacted]					
FPL Demand (MMBtu/day)	1,187,500	1,187,500	1,187,500	1,187,500	1,187,500	1,187,500
Projected EnergySecure Line Fuel Retention (%)	1.69%	1.69%	1.69%	1.69%	1.69%	1.69%
MDQ Required on Upstream P/L Project (MMBtu/day)	1,207,914	1,207,914	1,207,914	1,207,914	1,207,914	1,207,914
Company E Pipeline Proposal						
MDQ (MMBtu/day)	600,000	600,000	600,000	600,000	600,000	600,000
Upstream Pipeline Project Res. Fee ($/MMBtu)	[redacted]					
Capacity Addition 1						
MDQ (MMBtu/day)	157,040	157,040	157,040	157,040	157,040	157,040
Reservation Charge ($/MMBtu)	[redacted]					
Capacity Addition 2						
MDQ (MMBtu/day)	89,518	89,518	89,518	89,518	89,518	89,518
Reservation Charge ($/MMBtu)	[redacted]					
Capacity Addition 3						
MDQ (MMBtu/day)	183,347	183,347	183,347	183,347	183,347	183,347
Reservation Charge ($/MMBtu)	[redacted]					
Capacity Addition 4						
MDQ (MMBtu/day)	178,008	178,008	178,008	178,008	178,008	178,008
Reservation Charge ($/MMBtu)	[redacted]					
Annual Cost of Reservation Charges	[redacted]					

ATTACHMENT III B:

Project Demand Charges Incurred with Company E Upstream Pipeline Project

Annual Cost Escalator **2.50%**

Year	2049	2050	2051	2052	2053
Company E Proposed Rate - Escalated	[redacted]				
FPL Demand (MMBtu/day)	1,187,500	1,187,500	1,187,500	1,187,500	1,187,500
Projected EnergySecure Line Fuel Retention (%)	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
Company E Pipeline Proposal					
MDQ (MMBtu/day)	600,000	600,000	600,000	600,000	600,000
Upstream Pipeline Project Res. Fee ($/MMBtu)	[redacted]				
Capacity Addition 1					
MDQ (MMBtu/day)	157,040	157,040	157,040	157,040	157,040
Reservation Charge ($/MMBtu)	[redacted]				
Capacity Addition 2					
MDQ (MMBtu/day)	89,518	89,518	89,518	89,518	89,518
Reservation Charge ($/MMBtu)	[redacted]				
Capacity Addition 3					
MDQ (MMBtu/day)	183,347	183,347	183,347	183,347	183,347
Reservation Charge ($/MMBtu)	[redacted]				
Capacity Addition 4					
MDQ (MMBtu/day)	178,008	178,008	178,008	178,008	178,008
Reservation Charge ($/MMBtu)	[redacted]				
Annual Cost of Reservation Charges	[redacted]				

ATTACHMENT IV:

Projected Usage / Commodity Charges Incurred by FPL with Upstream Pipeline Project / Florida EnergySecure Line Project

Year	FPL Natural Gas Demand Served (MMBtu/day)	Average Load Factor for for new capacity (%) 1/	Fuel Gas Burned on EnergySecure Line: Gas Transported on Florida EnergySecure Line (MMBtu/year)	Florida EnergySecure Line Fuel Rate %	Fuel Gas Consumed on Florida EnergySecure Line (MMBtu/year)	Fuel Gas Retained by Upstream Pipeline Project: Projected Contract MDQ on Upstream Pipeline Project (MMBtu/day)	Annual Throughput Upstream Pipeline Project (MMBtu/year)	Upstream Pipeline Project Fuel Retention %	Total Projected Fuel Gas Retained (MMBtu/yr)	Calculated Cost of Fuel Gas: Henry Hub Cost of Gas ($/MMBtu) 2	Basis to Transco Zone 4 ($/MMBtu) 3/	Unit Cost of Fuel Gas ($/MMBtu)	Annual Cost of Fuel Gas ($/Year)	Usage Charges on Upstream Pipeline Project: Annual Throughput Upstream Pipeline (MMBtu/year)	Upstream Pipeline Proposed Comm. Rate ($/MMBtu)	Annual Cost of Usage Charges ($/Year)	Total Upstream Pipeline & EnergySecure Line Usage Costs ($/Year)	Unit Cost of Usage Charges per MMBtu Transported on Upstream P/L / EnergySecure ($/MMBtu)
Column	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18
Source	FPL Load Forecast	Footnote 1/	Footnote 1/	FPL - Collins Estimates	Col 3 * Col 4	Col 1 * (1 + Col 4)	Col 6 * Col 2 * days in year	Company E Proposal	[Col 7 / (1- Col 8)] - Col 7	Footnote 2/	Footnote 3/	Col 10 + Col 11	Col 12 * (Col 5 + Col 9)	Col 7	Footnote 4/	Col 1 * days in year * Col 2 * Col 15	Col 13 + Col 16	Col 17 / Col 3
2014	400,000	59%	85,422,300	0.55%	469,823	402,200	85,892,123	[redacted]	[redacted]	$ 8.692	$ 0.0525	$ 8.7449	[redacted]	85,892,123	[redacted]	[redacted]	[redacted]	[redacted]
2015	400,000	72%	104,757,800	0.55%	576,168	402,200	105,333,968	[redacted]	[redacted]	$ 9.192	$ 0.0525	$ 9.2445	[redacted]	105,333,968	[redacted]	[redacted]	[redacted]	[redacted]
2016	400,000	76%	111,114,000	0.55%	611,127	402,200	111,725,127	[redacted]	[redacted]	$ 9.692	$ 0.0525	$ 9.7440	[redacted]	111,725,127	[redacted]	[redacted]	[redacted]	[redacted]
2017	400,000	78%	114,002,300	0.55%	627,013	402,200	114,629,313	[redacted]	[redacted]	$ 10.291	$ 0.0525	$ 10.3435	[redacted]	114,629,313	[redacted]	[redacted]	[redacted]	[redacted]
2018	400,000	79%	115,486,300	0.55%	635,175	402,200	116,121,475	[redacted]	[redacted]	$ 11.090	$ 0.0525	$ 11.1428	[redacted]	116,121,475	[redacted]	[redacted]	[redacted]	[redacted]
2019	400,000	78%	114,415,400	0.55%	629,285	402,200	115,044,685	[redacted]	[redacted]	$ 12.089	$ 0.0525	$ 12.1420	[redacted]	115,044,685	[redacted]	[redacted]	[redacted]	[redacted]
2020	400,000	76%	111,570,500	0.55%	613,638	402,200	112,184,138	[redacted]	[redacted]	$ 12.742	$ 0.0525	$ 12.7942	[redacted]	112,184,138	[redacted]	[redacted]	[redacted]	[redacted]
2021	487,500	75%	133,453,125	0.55%	733,992	490,181	134,187,117	[redacted]	[redacted]	$ 12.997	$ 0.0525	$ 13.0490	[redacted]	134,187,117	[redacted]	[redacted]	[redacted]	[redacted]
2022	575,000	75%	157,406,250	0.55%	865,734	578,163	158,271,984	[redacted]	[redacted]	$ 13.256	$ 0.0525	$ 13.3089	[redacted]	158,271,984	[redacted]	[redacted]	[redacted]	[redacted]
2023	750,000	75%	205,312,500	0.93%	1,917,619	757,005	207,230,119	[redacted]	[redacted]	$ 13.522	$ 0.0525	$ 13.5740	[redacted]	207,230,119	[redacted]	[redacted]	[redacted]	[redacted]
2024	837,500	75%	229,893,750	1.07%	2,459,863	846,461	232,353,613	[redacted]	[redacted]	$ 13.792	$ 0.0525	$ 13.8444	[redacted]	232,353,613	[redacted]	[redacted]	[redacted]	[redacted]
2025	1,012,500	75%	277,171,875	1.69%	4,684,205	1,029,611	281,856,080	[redacted]	[redacted]	$ 14.068	$ 0.0525	$ 14.1202	[redacted]	281,856,080	[redacted]	[redacted]	[redacted]	[redacted]
2026	1,187,500	75%	325,078,125	1.69%	5,493,820	1,207,569	330,571,945	[redacted]	[redacted]	$ 14.349	$ 0.0525	$ 14.4015	[redacted]	330,571,945	[redacted]	[redacted]	[redacted]	[redacted]
2027	1,187,500	75%	325,078,125	1.69%	5,493,820	1,207,569	330,571,945	[redacted]	[redacted]	$ 14.636	$ 0.0525	$ 14.6885	[redacted]	330,571,945	[redacted]	[redacted]	[redacted]	[redacted]
2028	1,187,500	75%	325,968,750	1.69%	5,508,872	1,207,569	331,477,622	[redacted]	[redacted]	$ 14.929	$ 0.0525	$ 14.9812	[redacted]	331,477,622	[redacted]	[redacted]	[redacted]	[redacted]
2029	1,187,500	75%	325,078,125	1.69%	5,493,820	1,207,569	330,571,945	[redacted]	[redacted]	$ 15.227	$ 0.0525	$ 15.2797	[redacted]	330,571,945	[redacted]	[redacted]	[redacted]	[redacted]
2030	1,187,500	75%	325,078,125	1.69%	5,493,820	1,207,569	330,571,945	[redacted]	[redacted]	$ 15.532	$ 0.0525	$ 15.5842	[redacted]	330,571,945	[redacted]	[redacted]	[redacted]	[redacted]
2031	1,187,500	75%	325,078,125	1.69%	5,493,820	1,207,569	330,571,945	[redacted]	[redacted]	$ 15.842	$ 0.0525	$ 15.8948	[redacted]	330,571,945	[redacted]	[redacted]	[redacted]	[redacted]
2032	1,187,500	75%	325,968,750	1.69%	5,508,872	1,207,569	331,477,622	[redacted]	[redacted]	$ 16.159	$ 0.0525	$ 16.2116	[redacted]	331,477,622	[redacted]	[redacted]	[redacted]	[redacted]
2033	1,187,500	75%	325,078,125	1.69%	5,493,820	1,207,569	330,571,945	[redacted]	[redacted]	$ 16.482	$ 0.0525	$ 16.5348	[redacted]	330,571,945	[redacted]	[redacted]	[redacted]	[redacted]
2034	1,187,500	75%	325,078,125	1.69%	5,493,820	1,207,569	330,571,945	[redacted]	[redacted]	$ 16.812	$ 0.0525	$ 16.8644	[redacted]	330,571,945	[redacted]	[redacted]	[redacted]	[redacted]
2035	1,187,500	75%	325,078,125	1.69%	5,493,820	1,207,569	330,571,945	[redacted]	[redacted]	$ 17.148	$ 0.0525	$ 17.2006	[redacted]	330,571,945	[redacted]	[redacted]	[redacted]	[redacted]
2036	1,187,500	75%	325,968,750	1.69%	5,508,872	1,207,569	331,477,622	[redacted]	[redacted]	$ 17.491	$ 0.0525	$ 17.5435	[redacted]	331,477,622	[redacted]	[redacted]	[redacted]	[redacted]
2037	1,187,500	75%	325,078,125	1.69%	5,493,820	1,207,569	330,571,945	[redacted]	[redacted]	$ 17.841	$ 0.0525	$ 17.8933	[redacted]	330,571,945	[redacted]	[redacted]	[redacted]	[redacted]
2038	1,187,500	75%	325,078,125	1.69%	5,493,820	1,207,569	330,571,945	[redacted]	[redacted]	$ 18.198	$ 0.0525	$ 18.2501	[redacted]	330,571,945	[redacted]	[redacted]	[redacted]	[redacted]
2039	1,187,500	75%	325,078,125	1.69%	5,493,820	1,207,569	330,571,945	[redacted]	[redacted]	$ 18.561	$ 0.0525	$ 18.6140	[redacted]	330,571,945	[redacted]	[redacted]	[redacted]	[redacted]
2040	1,187,500	75%	325,968,750	1.69%	5,508,872	1,207,569	331,477,622	[redacted]	[redacted]	$ 18.933	$ 0.0525	$ 18.9852	[redacted]	331,477,622	[redacted]	[redacted]	[redacted]	[redacted]
2041	1,187,500	75%	325,078,125	1.69%	5,493,820	1,207,569	330,571,945	[redacted]	[redacted]	$ 19.311	$ 0.0525	$ 19.3638	[redacted]	330,571,945	[redacted]	[redacted]	[redacted]	[redacted]
2042	1,187,500	75%	325,078,125	1.69%	5,493,820	1,207,569	330,571,945	[redacted]	[redacted]	$ 19.697	$ 0.0525	$ 19.7500	[redacted]	330,571,945	[redacted]	[redacted]	[redacted]	[redacted]
2043	1,187,500	75%	325,078,125	1.69%	5,493,820	1,207,569	330,571,945	[redacted]	[redacted]	$ 20.091	$ 0.0525	$ 20.1439	[redacted]	330,571,945	[redacted]	[redacted]	[redacted]	[redacted]
2044	1,187,500	75%	325,968,750	1.69%	5,508,872	1,207,569	331,477,622	[redacted]	[redacted]	$ 20.493	$ 0.0525	$ 20.5457	[redacted]	331,477,622	[redacted]	[redacted]	[redacted]	[redacted]
2045	1,187,500	75%	325,078,125	1.69%	5,493,820	1,207,569	330,571,945	[redacted]	[redacted]	$ 20.903	$ 0.0525	$ 20.9555	[redacted]	330,571,945	[redacted]	[redacted]	[redacted]	[redacted]
2046	1,187,500	75%	325,078,125	1.69%	5,493,820	1,207,569	330,571,945	[redacted]	[redacted]	$ 21.321	$ 0.0525	$ 21.3735	[redacted]	330,571,945	[redacted]	[redacted]	[redacted]	[redacted]
2047	1,187,500	75%	325,078,125	1.69%	5,493,820	1,207,569	330,571,945	[redacted]	[redacted]	$ 21.747	$ 0.0525	$ 21.7999	[redacted]	330,571,945	[redacted]	[redacted]	[redacted]	[redacted]
2048	1,187,500	75%	325,968,750	1.69%	5,508,872	1,207,569	331,477,622	[redacted]	[redacted]	$ 22.182	$ 0.0525	$ 22.2348	[redacted]	331,477,622	[redacted]	[redacted]	[redacted]	[redacted]
2049	1,187,500	75%	325,078,125	1.69%	5,493,820	1,207,569	330,571,945	[redacted]	[redacted]	$ 22.626	$ 0.0525	$ 22.6784	[redacted]	330,571,945	[redacted]	[redacted]	[redacted]	[redacted]
2050	1,187,500	75%	325,078,125	1.69%	5,493,820	1,207,569	330,571,945	[redacted]	[redacted]	$ 23.078	$ 0.0525	$ 23.1308	[redacted]	330,571,945	[redacted]	[redacted]	[redacted]	[redacted]
2051	1,187,500	75%	325,078,125	1.69%	5,493,820	1,207,569	330,571,945	[redacted]	[redacted]	$ 23.540	$ 0.0525	$ 23.5923	[redacted]	330,571,945	[redacted]	[redacted]	[redacted]	[redacted]
2052	1,187,500	75%	325,968,750	1.69%	5,508,872	1,207,569	331,477,622	[redacted]	[redacted]	$ 24.011	$ 0.0525	$ 24.0631	[redacted]	331,477,622	[redacted]	[redacted]	[redacted]	[redacted]
2053	1,187,500	75%	325,078,125	1.69%	5,493,820	1,207,569	330,571,945	[redacted]	[redacted]	$ 24.491	$ 0.0525	$ 24.5432	[redacted]	330,571,945	[redacted]	[redacted]	[redacted]	[redacted]

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

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

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

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

ATTACHMENT V A:

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

	Cost Recovery for Release/Sale of Excess Capacity Utilizing Various Release Value Assumptions								
				Case A - Current Market		Case B - FGT Max Rate		Case C - No Value	
Year	FPL *Natural Gas* Fuel Requirements (MMBtu/day)	Pipeline *Project* Delivery Capacity (MMBtu/day)	Capacity *Available* For Release (MMBtu/day)	Unit Release Values 1/ ($/MMBtu)	Revenues from Capacity Release ($)	Unit Release Values 2/ ($/MMBtu)	Revenues from Capacity Release ($)	Unit Release Values ($/MMBtu)	Revenues from Capacity Release ($)
Column	1	2	3	4	5	6	7	8	9
Source	Attachment III A, *Column 3*	Attachment IIIA, *Column 4*	Col 2 - Col 1	See Footnote 1/	Col 4 * Col 3 * days	See Footnote 2/	Col 6 * Col 3 * days in year	Assume No Value	Col 8 * Col 3 * days in year
Sept 1, 2012 - Dec 1, 2012	-	-	-	$ 0.4614	$0	$ 1.5857	$0	$ -	$0
Dec 1, 2012 - Jan 1, 2013	30,000			$ 0.4614	$0	$ 1.5857	$0	$ -	$0
Jan 1, 2013 - March 1, 2013	30,000	-	-	$ 0.4614	$0	$ 1.5857	$0	$ -	$0
March 1, 2013 - Sept 1, 2013	50,000			$ 0.4614	$0	$ 1.5857	$0	$ -	$0
Sept 1, 2013 - Dec 1, 2013	200,000	-	-	$ 0.4614	$0	$ 1.5857	$0	$ -	$0
Dec 1, 2013 - Jan 1, 2014	230,000	-	-	$ 0.4614	$0	$ 1.5857	$0	$ -	$0
Jan 1, 2014 - March 1, 2014	*230,000*	*596,718*	*366,718*	$ 0.4614	$9,983,019	$ 1.5857	$34,308,784	$ -	$0
March 1, 2014 - June 1, 2014	250,000	596,718	346,718	$ 0.4614	$14,717,765	$ 1.5857	$50,580,755	$ -	$0
June 1 2014 - Jan 1 2015	400,000	596,718	196,718	$ 0.4614	$19,423,862	$ 1.5857	$66,754,264	$ -	$0
2015	400,000	596,718	196,718	$ 0.4729	$33,957,721	$ 1.5857	$113,856,572	$ -	$0
2016	400,000	596,718	196,718	$ 0.4848	$34,902,024	$ 1.5857	$114,168,508	$ -	$0
2017	400,000	596,718	196,718	$ 0.4969	$35,676,830	$ 1.5857	$113,856,572	$ -	$0
2018	400,000	596,718	196,718	$ 0.5093	$36,568,751	$ 1.5857	$113,856,572	$ -	$0
2019	400,000	596,718	196,718	$ 0.5220	$37,482,970	$ 1.5857	$113,856,572	$ -	$0
2020	400,000	596,718	196,718	$ 0.5351	$38,525,305	$ 1.5857	$114,168,508	$ -	$0
2021	487,500	596,718	109,218	$ 0.5485	$21,864,117	$ 1.5857	$63,213,278	$ -	$0
2022	575,000	596,718	21,718	$ 0.5622	$4,456,380	$ 1.5857	$12,569,984	$ -	$0
2023	750,000	800,000	50,000	$ 0.5762	$10,516,113	$ 1.5857	$28,939,025	$ -	$0
2024	837,500	1,000,000	162,500	$ 0.5906	$35,127,779	$ 1.5857	$94,309,508	$ -	$0
2025	1,012,500	1,250,000	237,500	$ 0.6054	$52,480,334	$ 1.5857	$137,460,369	$ -	$0
2026	1,187,500	1,250,000	62,500	$ 0.6205	$14,155,879	$ 1.5857	$36,173,781	$ -	$0
2027	1,187,500	1,250,000	62,500	$ 0.6360	$14,509,776	$ 1.5857	$36,173,781	$ -	$0
2028	1,187,500	1,250,000	62,500	$ 0.6519	$14,913,268	$ 1.5857	$36,272,888	$ -	$0
2029	1,187,500	1,250,000	62,500	$ 0.6682	$15,244,334	$ 1.5857	$36,173,781	$ -	$0
2030	1,187,500	1,250,000	62,500	$ 0.6850	$15,625,442	$ 1.5857	$36,173,781	$ -	$0
2031	1,187,500	1,250,000	62,500	$ 0.7021	$16,016,078	$ 1.5857	$36,173,781	$ -	$0
2032	1,187,500	1,250,000	62,500	$ 0.7196	$16,461,457	$ 1.5857	$36,272,888	$ -	$0
2033	1,187,500	1,250,000	62,500	$ 0.7376	$16,826,892	$ 1.5857	$36,173,781	$ -	$0
2034	1,187,500	1,250,000	62,500	$ 0.7561	$17,247,565	$ 1.5857	$36,173,781	$ -	$0
2035	1,187,500	1,250,000	62,500	$ 0.7750	$17,678,754	$ 1.5857	$36,173,781	$ -	$0
2036	1,187,500	1,250,000	62,500	$ 0.7943	$18,170,368	$ 1.5857	$36,272,888	$ -	$0
2037	1,187,500	1,250,000	62,500	$ 0.8142	$18,573,741	$ 1.5857	$36,173,781	$ -	$0
2038	1,187,500	1,250,000	62,500	$ 0.8345	$19,038,084	$ 1.5857	$36,173,781	$ -	$0
2039	1,187,500	1,250,000	62,500	$ 0.8554	$19,514,036	$ 1.5857	$36,173,781	$ -	$0
2040	1,187,500	1,250,000	62,500	$ 0.8768	$20,056,687	$ 1.5857	$36,272,888	$ -	$0
2041	1,187,500	1,250,000	62,500	$ 0.8987	$20,501,934	$ 1.5857	$36,173,781	$ -	$0
2042	1,187,500	1,250,000	62,500	$ 0.9212	$21,014,483	$ 1.5857	$36,173,781	$ -	$0
2043	1,187,500	1,250,000	62,500	$ 0.9442	$21,539,845	$ 1.5857	$36,173,781	$ -	$0
2044	1,187,500	1,250,000	62,500	$ 0.9678	$22,138,829	$ 1.5857	$36,272,888	$ -	$0
2045	1,187,500	1,250,000	62,500	$ 0.9920	$22,630,299	$ 1.5857	$36,173,781	$ -	$0
2046	1,187,500	1,250,000	62,500	$ 1.0168	$23,196,057	$ 1.5857	$36,173,781	$ -	$0
2047	1,187,500	1,250,000	62,500	$ 1.0422	$23,775,958	$ 1.5857	$36,173,781	$ -	$0
2048	1,187,500	1,250,000	62,500	$ 1.0683	$24,437,125	$ 1.5857	$36,272,888	$ -	$0
2049	1,187,500	1,250,000	62,500	$ 1.0950	$24,979,616	$ 1.5857	$36,173,781	$ -	$0
2050	1,187,500	1,250,000	62,500	$ 1.1224	$25,604,107	$ 1.5857	$36,173,781	$ -	$0
2051	1,187,500	1,250,000	62,500	$ 1.1504	$26,244,209	$ 1.5857	$36,173,781	$ -	$0
2052	1,187,500	1,250,000	62,500	$ 1.1792	$26,974,014	$ 1.5857	$36,272,888	$ -	$0
2053	1,187,500	1,250,000	62,500	$ 1.2087	$27,572,822	$ 1.5857	$36,173,781	$ -	$0

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

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

ATTACHMENT V B:

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

	Cost Recovery for Release/Sale of Excess Capacity Utilizing Various Release Value Assumptions			Case A - Current Market		Case B - FGT Max Rate		Case C - No Value	
Year	FPL Natural Gas Fuel Requirements (MMBtu/day)	Proposed Company B Delivery Capacity [1] (MMBtu/day)	Capacity Available For Release (MMBtu/day)	Unit Release Values [2] ($/MMBtu)	Revenues from Capacity Release ($)	Unit Release Values [3] ($/MMBtu)	Revenues from Capacity Release ($)	Unit Release Values ($/MMBtu)	Revenues from Capacity Release ($)
Column	1	2	3	4	5	6	7	8	9
Source	Attachment VA, Column 1	See Footnote 1/	Col 2 - Col 1	See Footnote 2/	Col 4 * Col 3 * days in year	See Footnote 3/	Col 6 * Col 3 * days in year	Assume No Value	Col 8 * Col 3 * days
Company B Capacity Project									
Sept 1, 2012 - Dec 1, 2012	-	50,000	50,000	$0.4614	$2,099,547	$ 1.5857	$7,214,935	$ -	$0
Dec 1, 2012 - Jan 1, 2013	30,000	50,000	20,000	$0.4614	$286,092	$ 1.5857	$983,134	$ -	$0
Jan 1, 2013 - March 1, 2013	30,000	50,000	20,000	$0.4614	$544,498	$ 1.5857	$1,871,126	$ -	$0
March 1, 2013 - Sept 1, 2013	50,000	50,000	0	$0.4614	$0	$ 1.5857	$0	$ -	$0
Sept 1, 2013 - Dec 1, 2013	200,000	400,000	200,000	$0.4614	$8,398,187	$ 1.5857	$28,859,740	$ -	$0
Dec 1, 2013 - Jan 1, 2014	230,000	400,000	170,000	$0.4614	$2,431,783	$ 1.5857	$8,356,639	$ -	$0
Jan 1, 2014 - March 1, 2014	230,000	400,000	170,000	$0.4614	$4,628,231	$ 1.5857	$15,904,571	$ -	$0
March 1, 2014 - June 1, 2014	250,000	400,000	150,000	$0.4614	$6,367,856	$ 1.5857	$21,882,660	$ -	$0
June 1 2014 - Jan 1 2015	400,000	400,000	0	$0.4614	$0	$ 1.5857	$0	$ -	$0
2015	400,000	400,000	-	$ -	$0	$ 1.5857	$0	$ -	$0
2016	400,000	400,000	-	$ -	$0	$ 1.5857	$0	$ -	$0
2017	400,000	400,000	-	$ -	$0	$ 1.5857	$0	$ -	$0
2018	400,000	400,000	-	$ -	$0	$ 1.5857	$0	$ -	$0
2019	400,000	400,000	-	$ -	$0	$ 1.5857	$0	$ -	$0
2020	400,000	400,000	-	$ -	$0	$ 1.5857	$0	$ -	$0
2021	487,500	400,000	-	$ -	$0	$ 1.5857	$0	$ -	$0
2022	575,000	400,000	-	$ -	$0	$ 1.5857	$0	$ -	$0
2023	750,000	400,000	-	$ -	$0	$ 1.5857	$0	$ -	$0
2024	837,500	837,500	-	$ -	$0	$ 1.5857	$0	$ -	$0
2025	1,012,500	1,012,500	-	$ -	$0	$ 1.5857	$0	$ -	$0
2026	1,187,500	1,187,500	-	$ -	$0	$ 1.5857	$0	$ -	$0
2027	1,187,500	1,187,500	-	$ -	$0	$ 1.5857	$0	$ -	$0
2028	1,187,500	1,187,500	-	$ -	$0	$ 1.5857	$0	$ -	$0
2029	1,187,500	1,187,500	-	$ -	$0	$ 1.5857	$0	$ -	$0
2030	1,187,500	1,187,500	-	$ -	$0	$ 1.5857	$0	$ -	$0
2031	1,187,500	1,187,500	-	$ -	$0	$ 1.5857	$0	$ -	$0
2032	1,187,500	1,187,500	-	$ -	$0	$ 1.5857	$0	$ -	$0
2033	1,187,500	1,187,500	-	$ -	$0	$ 1.5857	$0	$ -	$0
2034	1,187,500	1,187,500	-	$ -	$0	$ 1.5857	$0	$ -	$0
2035	1,187,500	1,187,500	-	$ -	$0	$ 1.5857	$0	$ -	$0
2036	1,187,500	1,187,500	-	$ -	$0	$ 1.5857	$0	$ -	$0
2037	1,187,500	1,187,500	-	$ -	$0	$ 1.5857	$0	$ -	$0
2038	1,187,500	1,187,500	-	$ -	$0	$ 1.5857	$0	$ -	$0
2039	1,187,500	1,187,500	-	$ -	$0	$ 1.5857	$0	$ -	$0
2040	1,187,500	1,187,500	-	$ -	$0	$ 1.5857	$0	$ -	$0
2041	1,187,500	1,187,500	-	$ -	$0	$ 1.5857	$0	$ -	$0
2042	1,187,500	1,187,500	-	$ -	$0	$ 1.5857	$0	$ -	$0
2043	1,187,500	1,187,500	-	$ -	$0	$ 1.5857	$0	$ -	$0
2044	1,187,500	1,187,500	-	$ -	$0	$ 1.5857	$0	$ -	$0
2045	1,187,500	1,187,500	-	$ -	$0	$ 1.5857	$0	$ -	$0
2046	1,187,500	1,187,500	-	$ -	$0	$ 1.5857	$0	$ -	$0
2047	1,187,500	1,187,500	-	$ -	$0	$ 1.5857	$0	$ -	$0
2048	1,187,500	1,187,500	-	$ -	$0	$ 1.5857	$0	$ -	$0
2049	1,187,500	1,187,500	-	$ -	$0	$ 1.5857	$0	$ -	$0
2050	1,187,500	1,187,500	-	$ -	$0	$ 1.5857	$0	$ -	$0
2051	1,187,500	1,187,500	-	$ -	$0	$ 1.5857	$0	$ -	$0
2052	1,187,500	1,187,500	-	$ -	$0	$ 1.5857	$0	$ -	$0
2053	1,187,500	1,187,500	-	$ -	$0	$ 1.5857	$0	$ -	$0

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

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

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

ATTACHMENT VI A:

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

Year	Upstream Pipeline Project / Florida EnergySecure Line Project							Variable Costs of FPL's Current Contracted FGT Service 4/					Economic Dispatch Savings vs. Contracted FGT Service			
	Unsubscribed Capacity Not Released in Secondary Market (MMBtu/day)	FPL Natural Gas Demand Served (MMBtu/day)	Average Load Factor for New Capacity (%) 1/	Average Unutilized Subscribed Capacity (MMBtu/yr)	Total Capacity Available for Economic Dispatch (MMBtu/yr)	Projected Unit Price of Gas into Upstream Pipeline/FPL Pipeline ($/MMBtu)	Variable Cost on Upstream Pipeline / FPL Project ($/MMBtu)	FGT Fuel Retention Rate (%)	Projected Henry Hub Cost of Gas ($/MMBtu) 2/	Projected Basis to FGT Zone 3 ($/MMBtu) 3/	Projected Unit Cost of Gas into FGT ($/MMBtu)	Variable (fuel) Cost on FGT Pipeline System ($/MMBtu)	Variable Service Cost Savings with New Pipeline System ($/MMBtu)	Gas Cost Savings with New Pipeline System ($/MMBtu)	Total Economic Dispatch Savings Available ($/MMBtu)	Economic Dispatch Savings Available ($/Year)
Column	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16
Source	Attachment V	FPL Base Case Resource Plan	See Footnote 1/	Col 2 * days in year * (1 - Col 3)	(Col 1 * days in year) + Col 4	Attachment IV, Col 12	Attachment IV, Col 17	FGT Phase VIII Filing - Exhibit N	See Footnote 2/	See Footnote 3/	Col 9 + Col 10	[Col 11 / (1 - Col 8)] - Col 11	Col 12 - Col 7	Col 11 - Col 6	Col 13 + Col 14	Col 5 * Col 15
2014	-	400,000	59%	60,577,700	60,577,700	$ 8.7449	$ 0.2443	3.26%	$ 8.692	$ 0.0968	$ 8.789	$ 0.2962	$0.0519	$ 0.0443	0.0962	$ 5,828,278
2015	-	400,000	72%	41,242,200	41,242,200	$ 9.2445	$ 0.2571	3.26%	$ 9.192	$ 0.0968	$ 9.289	$ 0.3130	$0.0559	$ 0.0443	0.1002	$ 4,133,139
2016	-	400,000	76%	35,286,000	35,286,000	$ 9.7440	$ 0.2700	3.26%	$ 9.692	$ 0.0968	$ 9.788	$ 0.3299	$0.0599	$ 0.0443	0.1042	$ 3,676,767
2017	-	400,000	78%	31,997,700	31,997,700	$ 10.3435	$ 0.2852	3.26%	$ 10.291	$ 0.0968	$ 10.388	$ 0.3501	$0.0648	$ 0.0443	0.1091	$ 3,492,079
2018	-	400,000	79%	30,513,700	30,513,700	$ 11.1428	$ 0.3053	3.26%	$ 11.090	$ 0.0968	$ 11.187	$ 0.3770	$0.0717	$ 0.0443	0.1160	$ 3,539,604
2019	-	400,000	78%	31,584,600	31,584,600	$ 12.1420	$ 0.3302	3.26%	$ 12.089	$ 0.0968	$ 12.186	$ 0.4107	$0.0805	$ 0.0443	0.1248	$ 3,941,567
2020	-	400,000	76%	34,829,500	34,829,500	$ 12.7942	$ 0.3468	3.26%	$ 12.742	$ 0.0968	$ 12.839	$ 0.4326	$0.0859	$ 0.0443	0.1302	$ 4,533,935
2021	-	487,500	75%	44,484,375	44,484,375	$ 13.0490	$ 0.3539	3.26%	$ 12.997	$ 0.0968	$ 13.093	$ 0.4412	$0.0873	$ 0.0443	0.1316	$ 5,856,337
2022	-	575,000	75%	52,468,750	52,468,750	$ 13.3089	$ 0.3611	3.26%	$ 13.256	$ 0.0968	$ 13.353	$ 0.4500	$0.0888	$ 0.0443	0.1331	$ 6,986,102
2023	-	750,000	75%	68,437,500	68,437,500	$ 13.5740	$ 0.4216	3.26%	$ 13.522	$ 0.0968	$ 13.618	$ 0.4589	$0.0373	$ 0.0443	0.0816	$ 5,583,921
2024	-	837,500	75%	76,631,250	76,631,250	$ 13.8444	$ 0.4494	3.26%	$ 13.792	$ 0.0968	$ 13.889	$ 0.4680	$0.0186	$ 0.0443	0.0629	$ 4,820,803
2025	-	1,012,500	75%	92,390,625	92,390,625	$ 14.1202	$ 0.5478	3.26%	$ 14.068	$ 0.0968	$ 14.165	$ 0.4773	($0.0704)	$ 0.0443	-	$ -
2026	-	1,187,500	75%	108,359,375	108,359,375	$ 14.4015	$ 0.5589	3.26%	$ 14.349	$ 0.0968	$ 14.446	$ 0.4868	($0.0721)	$ 0.0443	-	$ -
2027	-	1,187,500	75%	108,359,375	108,359,375	$ 14.6885	$ 0.5703	3.26%	$ 14.636	$ 0.0968	$ 14.733	$ 0.4965	($0.0738)	$ 0.0443	-	$ -
2028	-	1,187,500	75%	108,656,250	108,656,250	$ 14.9812	$ 0.5819	3.26%	$ 14.929	$ 0.0968	$ 15.025	$ 0.5063	($0.0755)	$ 0.0443	-	$ -
2029	-	1,187,500	75%	108,359,375	108,359,375	$ 15.2797	$ 0.5937	3.26%	$ 15.227	$ 0.0968	$ 15.324	$ 0.5164	($0.0773)	$ 0.0443	-	$ -
2030	-	1,187,500	75%	108,359,375	108,359,375	$ 15.5842	$ 0.6058	3.26%	$ 15.532	$ 0.0968	$ 15.629	$ 0.5267	($0.0792)	$ 0.0443	-	$ -
2031	-	1,187,500	75%	108,359,375	108,359,375	$ 15.8948	$ 0.6182	3.26%	$ 15.842	$ 0.0968	$ 15.939	$ 0.5371	($0.0810)	$ 0.0443	-	$ -
2032	-	1,187,500	75%	108,656,250	108,656,250	$ 16.2116	$ 0.6307	3.26%	$ 16.159	$ 0.0968	$ 16.256	$ 0.5478	($0.0829)	$ 0.0443	-	$ -
2033	-	1,187,500	75%	108,359,375	108,359,375	$ 16.5348	$ 0.6436	3.26%	$ 16.482	$ 0.0968	$ 16.579	$ 0.5587	($0.0849)	$ 0.0443	-	$ -
2034	-	1,187,500	75%	108,359,375	108,359,375	$ 16.8644	$ 0.6567	3.26%	$ 16.812	$ 0.0968	$ 16.909	$ 0.5698	($0.0869)	$ 0.0443	-	$ -
2035	-	1,187,500	75%	108,359,375	108,359,375	$ 17.2006	$ 0.6701	3.26%	$ 17.148	$ 0.0968	$ 17.245	$ 0.5811	($0.0890)	$ 0.0443	-	$ -
2036	-	1,187,500	75%	108,656,250	108,656,250	$ 17.5435	$ 0.6837	3.26%	$ 17.491	$ 0.0968	$ 17.588	$ 0.5927	($0.0911)	$ 0.0443	-	$ -
2037	-	1,187,500	75%	108,359,375	108,359,375	$ 17.8933	$ 0.6977	3.26%	$ 17.841	$ 0.0968	$ 17.938	$ 0.6045	($0.0932)	$ 0.0443	-	$ -
2038	-	1,187,500	75%	108,359,375	108,359,375	$ 18.2501	$ 0.7119	3.26%	$ 18.198	$ 0.0968	$ 18.294	$ 0.6165	($0.0954)	$ 0.0443	-	$ -
2039	-	1,187,500	75%	108,359,375	108,359,375	$ 18.6140	$ 0.7264	3.26%	$ 18.561	$ 0.0968	$ 18.658	$ 0.6288	($0.0977)	$ 0.0443	-	$ -
2040	-	1,187,500	75%	108,656,250	108,656,250	$ 18.9852	$ 0.7412	3.26%	$ 18.933	$ 0.0968	$ 19.029	$ 0.6413	($0.1000)	$ 0.0443	-	$ -
2041	-	1,187,500	75%	108,359,375	108,359,375	$ 19.3638	$ 0.7564	3.26%	$ 19.311	$ 0.0968	$ 19.408	$ 0.6540	($0.1023)	$ 0.0443	-	$ -
2042	-	1,187,500	75%	108,359,375	108,359,375	$ 19.7500	$ 0.7718	3.26%	$ 19.697	$ 0.0968	$ 19.794	$ 0.6670	($0.1047)	$ 0.0443	-	$ -
2043	-	1,187,500	75%	108,359,375	108,359,375	$ 20.1439	$ 0.7875	3.26%	$ 20.091	$ 0.0968	$ 20.188	$ 0.6803	($0.1072)	$ 0.0443	-	$ -
2044	-	1,187,500	75%	108,656,250	108,656,250	$ 20.5457	$ 0.8036	3.26%	$ 20.493	$ 0.0968	$ 20.590	$ 0.6939	($0.1097)	$ 0.0443	-	$ -
2045	-	1,187,500	75%	108,359,375	108,359,375	$ 20.9555	$ 0.8200	3.26%	$ 20.903	$ 0.0968	$ 21.000	$ 0.7077	($0.1123)	$ 0.0443	-	$ -
2046	-	1,187,500	75%	108,359,375	108,359,375	$ 21.3735	$ 0.8367	3.26%	$ 21.321	$ 0.0968	$ 21.418	$ 0.7217	($0.1150)	$ 0.0443	-	$ -
2047	-	1,187,500	75%	108,359,375	108,359,375	$ 21.7999	$ 0.8538	3.26%	$ 21.747	$ 0.0968	$ 21.844	$ 0.7361	($0.1177)	$ 0.0443	-	$ -
2048	-	1,187,500	75%	108,656,250	108,656,250	$ 22.2348	$ 0.8713	3.26%	$ 22.182	$ 0.0968	$ 22.279	$ 0.7508	($0.1205)	$ 0.0443	-	$ -
2049	-	1,187,500	75%	108,359,375	108,359,375	$ 22.6784	$ 0.8890	3.26%	$ 22.626	$ 0.0968	$ 22.723	$ 0.7657	($0.1233)	$ 0.0443	-	$ -
2050	-	1,187,500	75%	108,359,375	108,359,375	$ 23.1308	$ 0.9072	3.26%	$ 23.078	$ 0.0968	$ 23.175	$ 0.7810	($0.1262)	$ 0.0443	-	$ -
2051	-	1,187,500	75%	108,359,375	108,359,375	$ 23.5923	$ 0.9257	3.26%	$ 23.540	$ 0.0968	$ 23.637	$ 0.7965	($0.1292)	$ 0.0443	-	$ -
2052	-	1,187,500	75%	108,656,250	108,656,250	$ 24.0631	$ 0.9446	3.26%	$ 24.011	$ 0.0968	$ 24.107	$ 0.8124	($0.1323)	$ 0.0443	-	$ -
2053	-	1,187,500	75%	108,359,375	108,359,375	$ 24.5432	$ 0.9639	3.26%	$ 24.491	$ 0.0968	$ 24.588	$ 0.8286	($0.1354)	$ 0.0443	-	$ -

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

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

3/ Basis differential between Henry Hub and FGT Zone 3 equal to value included within FPL fuel price forecast developed 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 displace this higher cost FGT capacity. Thus, economic dispatch value is represented by the difference in cost between the use of the proposed project capacity and the FGT capacity under contract.

ATTACHMENT VI B:

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

	Upstream Pipeline Project / Florida EnergySecure Line Project							Variable Costs of FPL's Current Contracted FGT Service 4/					Economic Dispatch Savings vs. Contracted FGT Service			
Year	Average Unsubscribed Capacity Not Released in Secondary Market (MMBtu/day)	FPL Natural Gas Demand Served (MMBtu/day)	Average Load Factor for for new capacity (%) 1/	Average Unutilized Subscribed Capacity (MMBtu/yr) 1/	Total Capacity Available for Economic Dispatch (MMBtu/yr)	Projected Unit Price of Gas into Upstream Pipeline/FPL Pipeline ($/MMBtu)	Variable Cost on Upstream Pipeline / FPL Project ($/MMBtu)	FGT Fuel Retention Rate (%)	Projected Henry Hub Cost of Gas ($/MMBtu) 2/	Projected Basis to FGT Zone 3 ($/MMBtu) 3/	Projected Unit Cost of Gas into FGT ($/MMBtu)	Variable (fuel) Cost on FGT Pipeline System ($/MMBtu)	Variable Service Cost Savings with New Pipeline System ($/MMBtu)	Gas Cost Savings with New Pipeline System ($/MMBtu)	Total Economic Dispatch Savings Available ($/MMBtu)	Economic Dispatch Savings Available ($/Year)
Column	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16
Source	Attachment VA	FPL Base Case Resource Plan	See Footnote 1/	Col 2 * days in year * (1 - Col 3)	(Col 1 * days in year) + Col 4	Attachment IV, Col 12	Attachment IV, Col 17	FGT Phase VIII Filing - Exhibit N	See Footnote 2/	See Footnote 3/	Col 9 + Col 10	[Col 11 / (1 - Col 8)] - Col 11	Col 12 - Col 7	Col 11 - Col 6	Col 13 + Col 14	Col 5 * Col 15
2014	262,006	400,000	59%	60,577,700	156,209,789	$ 8.7449	$ 0.2443	3.26%	$ 8.692	$ 0.0968	$ 8.789	$ 0.2962	$0.0519	$ 0.0443	0.0962	$ 15,029,194
2015	196,718	400,000	72%	41,242,200	113,044,289	$ 9.2445	$ 0.2571	3.26%	$ 9.192	$ 0.0968	$ 9.289	$ 0.3130	$0.0559	$ 0.0443	0.1002	$ 11,328,875
2016	196,718	400,000	76%	35,286,000	107,284,807	$ 9.7440	$ 0.2700	3.26%	$ 9.692	$ 0.0968	$ 9.788	$ 0.3299	$0.0599	$ 0.0443	0.1042	$ 11,178,973
2017	196,718	400,000	78%	31,997,700	103,799,789	$ 10.3435	$ 0.2852	3.26%	$ 10.291	$ 0.0968	$ 10.388	$ 0.3501	$0.0648	$ 0.0443	0.1091	$ 11,328,223
2018	196,718	400,000	79%	30,513,700	102,315,789	$ 11.1428	$ 0.3053	3.26%	$ 11.090	$ 0.0968	$ 11.187	$ 0.3770	$0.0717	$ 0.0443	0.1160	$ 11,868,681
2019	196,718	400,000	78%	31,584,600	103,386,689	$ 12.1420	$ 0.3302	3.26%	$ 12.089	$ 0.0968	$ 12.186	$ 0.4107	$0.0805	$ 0.0443	0.1248	$ 12,902,034
2020	196,718	400,000	76%	34,829,500	106,828,307	$ 12.7942	$ 0.3468	3.26%	$ 12.742	$ 0.0968	$ 12.839	$ 0.4326	$0.0859	$ 0.0443	0.1302	$ 13,906,389
2021	109,218	487,500	75%	44,484,375	84,348,964	$ 13.0490	$ 0.3539	3.26%	$ 12.997	$ 0.0968	$ 13.093	$ 0.4412	$0.0873	$ 0.0443	0.1316	$ 11.104.481
2022	21,718	575,000	75%	52,468,750	60,395,839	$ 13.3089	$ 0.3611	3.26%	$ 13.256	$ 0.0968	$ 13.353	$ 0.4500	$0.0888	$ 0.0443	0.1331	$ 8,041,577
2023	50,000	750,000	75%	68,437,500	86,687,500	$ 13.5740	$ 0.4216	3.26%	$ 13.522	$ 0.0968	$ 13.618	$ 0.4589	$0.0373	$ 0.0443	0.0816	$ 7,072,966
2024	162,500	837,500	75%	76,631,250	136,106,250	$ 13.8444	$ 0.4494	3.26%	$ 13.792	$ 0.0968	$ 13.889	$ 0.4680	$0.0186	$ 0.0443	0.0629	$ 8,562,322
2025	237,500	1,012,500	75%	92,390,625	179,078,125	$ 14.1202	$ 0.5478	3.26%	$ 14.068	$ 0.0968	$ 14.165	$ 0.4773	($0.0704)	$ 0.0443	-	$ -
2026	62,500	1,187,500	75%	108,359,375	131,171,875	$ 14.4015	$ 0.5589	3.26%	$ 14.349	$ 0.0968	$ 14.446	$ 0.4868	($0.0721)	$ 0.0443	-	$ -
2027	62,500	1,187,500	75%	108,359,375	131,171,875	$ 14.6885	$ 0.5703	3.26%	$ 14.636	$ 0.0968	$ 14.733	$ 0.4965	($0.0738)	$ 0.0443	-	$ -
2028	62,500	1,187,500	75%	108,656,250	131,531,250	$ 14.9812	$ 0.5819	3.26%	$ 14.929	$ 0.0968	$ 15.025	$ 0.5063	($0.0755)	$ 0.0443	-	$ -
2029	62,500	1,187,500	75%	108,359,375	131,171,875	$ 15.2797	$ 0.5937	3.26%	$ 15.227	$ 0.0968	$ 15.324	$ 0.5164	($0.0773)	$ 0.0443	-	$ -
2030	62,500	1,187,500	75%	108,359,375	131,171,875	$ 15.5842	$ 0.6058	3.26%	$ 15.532	$ 0.0968	$ 15.629	$ 0.5267	($0.0792)	$ 0.0443	-	$ -
2031	62,500	1,187,500	75%	108,359,375	131,171,875	$ 15.8948	$ 0.6182	3.26%	$ 15.842	$ 0.0968	$ 15.939	$ 0.5371	($0.0810)	$ 0.0443	-	$ -
2032	62,500	1,187,500	75%	108,656,250	131,531,250	$ 16.2116	$ 0.6307	3.26%	$ 16.159	$ 0.0968	$ 16.256	$ 0.5478	($0.0829)	$ 0.0443	-	$ -
2033	62,500	1,187,500	75%	108,359,375	131,171,875	$ 16.5348	$ 0.6436	3.26%	$ 16.482	$ 0.0968	$ 16.579	$ 0.5587	($0.0849)	$ 0.0443	-	$ -
2034	62,500	1,187,500	75%	108,359,375	131,171,875	$ 16.8644	$ 0.6567	3.26%	$ 16.812	$ 0.0968	$ 16.909	$ 0.5698	($0.0869)	$ 0.0443	-	$ -
2035	62,500	1,187,500	75%	108,359,375	131,171,875	$ 17.2006	$ 0.6701	3.26%	$ 17.148	$ 0.0968	$ 17.245	$ 0.5811	($0.0890)	$ 0.0443	-	$ -
2036	62,500	1,187,500	75%	108,656,250	131,531,250	$ 17.5435	$ 0.6837	3.26%	$ 17.491	$ 0.0968	$ 17.588	$ 0.5927	($0.0911)	$ 0.0443	-	$ -
2037	62,500	1,187,500	75%	108,359,375	131,171,875	$ 17.8933	$ 0.6977	3.26%	$ 17.841	$ 0.0968	$ 17.938	$ 0.6045	($0.0932)	$ 0.0443	-	$ -
2038	62,500	1,187,500	75%	108,359,375	131,171,875	$ 18.2501	$ 0.7119	3.26%	$ 18.198	$ 0.0968	$ 18.294	$ 0.6165	($0.0954)	$ 0.0443	-	$ -
2039	62,500	1,187,500	75%	108,359,375	131,171,875	$ 18.6140	$ 0.7264	3.26%	$ 18.561	$ 0.0968	$ 18.658	$ 0.6288	($0.0977)	$ 0.0443	-	$ -
2040	62,500	1,187,500	75%	108,656,250	131,531,250	$ 18.9852	$ 0.7412	3.26%	$ 18.933	$ 0.0968	$ 19.029	$ 0.6413	($0.1000)	$ 0.0443	-	$ -
2041	62,500	1,187,500	75%	108,359,375	131,171,875	$ 19.3638	$ 0.7564	3.26%	$ 19.311	$ 0.0968	$ 19.408	$ 0.6540	($0.1023)	$ 0.0443	-	$ -
2042	62,500	1,187,500	75%	108,359,375	131,171,875	$ 19.7500	$ 0.7718	3.26%	$ 19.697	$ 0.0968	$ 19.794	$ 0.6670	($0.1047)	$ 0.0443	-	$ -
2043	62,500	1,187,500	75%	108,359,375	131,171,875	$ 20.1439	$ 0.7875	3.26%	$ 20.091	$ 0.0968	$ 20.188	$ 0.6803	($0.1072)	$ 0.0443	-	$ -
2044	62,500	1,187,500	75%	108,656,250	131,531,250	$ 20.5457	$ 0.8036	3.26%	$ 20.493	$ 0.0968	$ 20.590	$ 0.6939	($0.1097)	$ 0.0443	-	$ -
2045	62,500	1,187,500	75%	108,359,375	131,171,875	$ 20.9555	$ 0.8200	3.26%	$ 20.903	$ 0.0968	$ 21.000	$ 0.7077	($0.1123)	$ 0.0443	-	$ -
2046	62,500	1,187,500	75%	108,359,375	131,171,875	$ 21.3735	$ 0.8367	3.26%	$ 21.321	$ 0.0968	$ 21.418	$ 0.7217	($0.1150)	$ 0.0443	-	$ -
2047	62,500	1,187,500	75%	108,359,375	131,171,875	$ 21.7999	$ 0.8538	3.26%	$ 21.747	$ 0.0968	$ 21.844	$ 0.7361	($0.1177)	$ 0.0443	-	$ -
2048	62,500	1,187,500	75%	108,656,250	131,531,250	$ 22.2348	$ 0.8713	3.26%	$ 22.182	$ 0.0968	$ 22.279	$ 0.7508	($0.1205)	$ 0.0443	-	$ -
2049	62,500	1,187,500	75%	108,359,375	131,171,875	$ 22.6784	$ 0.8890	3.26%	$ 22.626	$ 0.0968	$ 22.723	$ 0.7657	($0.1233)	$ 0.0443	-	$ -
2050	62,500	1,187,500	75%	108,359,375	131,171,875	$ 23.1308	$ 0.9072	3.26%	$ 23.078	$ 0.0968	$ 23.175	$ 0.7810	($0.1262)	$ 0.0443	-	$ -
2051	62,500	1,187,500	75%	108,359,375	131,171,875	$ 23.5923	$ 0.9257	3.26%	$ 23.540	$ 0.0968	$ 23.637	$ 0.7965	($0.1292)	$ 0.0443	-	$ -
2052	62,500	1,187,500	75%	108,656,250	131,531,250	$ 24.0631	$ 0.9446	3.26%	$ 24.011	$ 0.0968	$ 24.107	$ 0.8124	($0.1323)	$ 0.0443	-	$ -
2053	62,500	1,187,500	75%	108,359,375	131,171,875	$ 24.5432	$ 0.9639	3.26%	$ 24.491	$ 0.0968	$ 24.588	$ 0.8286	($0.1354)	$ 0.0443	-	$ -

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

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

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

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