Company E/FES system would consist of a new 360-mile interstate gas pipeline to be constructed, owned and operated by an entity defined by FPL as "Company E" that would receive gas at Transco Station 85 and deliver this gas to the originating point of FPL's pipeline, projected to be located near FGT Station 16. As an interstate gas pipeline, the Company E facilities would be regulated by the Federal Energy Regulatory Commission (FERC). In addition, FPL would build, own and operate a new 279-mile intrastate gas pipeline entirely within the State of Florida, thus not under the jurisdiction of the FERC. The FES pipeline would receive gas at FGT Station 16 and deliver this gas to the Cape Canaveral and Riviera power stations.

Q. What would the foregoing facilities cost?

A. Information supplied by FPL indicates that the initial capital investment requirements associated with the combined Company E/FES system would be as follows: [redacted] for the Company E pipeline plus $1.6 billion for the FES pipeline, i.e., a total of [redacted] to be spent between 2012 through 2014.

<u>**FPL's Gas Price Projections**</u>

Q. Concerning the price of natural gas, what are FPL's major underlying economic assumptions in this application?

A. In Exhibit BSA-2, I have assembled FPL's major underlying economic assumptions relating to natural gas prices, and its projections of how these will change in the future at specific locations along the FGT and Transco systems, including Henry Hub, FGT Zones 1, 2 and 3, and Transco Station 85 (which is situated within Transco Zone 4). FPL has also made economic assumptions concerning how prices among a number of locations will differ from one another in the future that are shown in the exhibit.

Q. Do you agree with FPL's assumptions?

A. I do not, and it is hard to imagine that FPL has proceeded this far in its planning process based on these price forecasts and projected basis relationships. FPL has failed in my judgment to set forth a robust, internally consistent set of economic forecasts that would normally be forthcoming in conjunction with major construction project requiring the expenditure of [redacted], $1.6 billion of which it is asking this Commission to include in its rate base for its electric ratepayers to directly pay.

Q. Please explain.

A. First, the most important price of wholesale natural gas in North America is the price at Henry Hub, located in Erath, Louisiana. Henry Hub is the location for physical deliveries and receipts that is referenced in the NYMEX gas futures contract, and hosts a robust physical gas trade as well. Henry Hub has grown in the past two decades to become the continent's single most important gas pricing location, against which gas at other locations is measured.

Gas prices in North America are set through the interaction of supply and demand. Many factors will affect future gas prices at Henry Hub, e.g., including the weather; decreased offshore gas production; increased gas supplies from unconventional gas production and from LNG; lower future demand with recessions, efficient uses and electricity generation from renewables; peak period gas demands; higher future demand with growth and environmental/carbon rules; oil prices; addition of new pipelines and other infrastructure; and more. A robust forecast of Henry Hub prices is one that comprehends these critical factors.

Q. What is FPL's Henry Hub gas price forecast?

A. As shown in Exhibit BSA-2, FPL's Henry Hub price forecast may be described in general as follows:

- From now through 2020, Henry Hub prices in the FPL forecast fall then rise;

- From 2020 through 2062, a period of 42 years, Henry Hub gas prices in the FPL forecast do not change at all, i.e., they are constant in real dollars, plus an inflation factor of 2% per year.

Q. Are these Henry Hub price forecasts reasonable for planning purposes?

A. No they are not. FPL has offered very simplistic gas price forecasts that, on their face, could not comprehend, in any explainable way, the myriad supply and demand factors that might influence Henry Hub prices in the future. Instead, all of this is simply assumed away in one long, straight, flat line. In my opinion, this is not a reasonable starting point to consider a future decision affecting millions of electricity ratepayers. No one can predict future fuel prices with certainty, but the forecasting process requires that supply and demand conditions be thought through, i.e., that the numbers reflect a reckoning of the information we know about concerning future changes, such as the effect of new gas pipelines, new rules that will tighten energy demand and require renewable sources of electricity, carbon rules, international gas supply and demand, and more. In the context of a proposed [redacted] capital expenditure for new gas pipeline capacity, these cannot prudently be swept away, or somehow "averaged" into a long, straight, flat line.

More importantly, the use of never-changing Henry Hub gas price forecast in real dollars for 42 years sharply undermines FPL's decision to build the FES pipeline at all. FPL may have severely understated future natural gas prices because depletion of gas resources and diversion of LNG supplies away to higher-paying markets in Europe and Asia – these kinds of factors may cause Henry Hub gas prices to rise in real dollar terms, plus more for inflation.

In short, FPL's simplistic Henry Hub forecast suggests it has skipped doing its gas pricing analysis due diligence in a way that would justify a major new gas transportation expenditure of this magnitude.

Q. Are FPL's gas basis forecasts reasonable, i.e., its projection of the future differences among key southeastern gas pricing points?

A. Wholesale natural gas prices at locations other than Henry Hub are typically expressed as the difference between the price at a pricing point minus the price at Henry Hub, known as basis differentials. For instance, NYMEX currently offers futures contracts in basis differentials between the price of gas at 53 different locations and the price of gas at Henry Hub. These futures contracts are referred to as basis swaps, such as the Transco Zone 4 basis swap referred to by Witness Sexton (Sexton Direct Testimony, page 27).

Exhibit BSA-2 identifies FPL's projection of prices relative to Henry Hub at Transco Zone 4 (taken to equate to Transco Station 85) and at FGT Zone 3. Here again, as is the case for FPL's Henry Hub price projections beyond 2020, its projected price differentials are flat, unchanging, even with inflation added in. In other words, in the case of price differentials, no inflation factor is added to the forecast, thus the differential between prices at Transco Station 85 and at Henry Hub is assumed to equal $0.0525 per MMBtu above the Henry Hub price, year in and year out, never changing for 40 years. Likewise, the differential between FGT Zone 3 and Henry Hub is assumed to equal $0.0968 per MMBtu over the Henry Hub price, again exactly the same number for 40 years. (Sexton Direct, Exhibit TCS-7, pages 11 and 23) These differentials result in continuously $0.0443 per MMBtu lower prices at Station 85 than at FGT Zone 3, for 40 years.

In response to FGT data requests, FPL offered other basis forecasts among FGT Zones 1, 2 and 3 that are even further afield in my view. Exhibit BSA-2 reproduces portions of FPL's Excel spreadsheet submitted in response to FGT's First POD, No. 1, Document FPL001015.1, entitled "Long term Price Forecast Methodology – 2020 EIA E," in tab labeled "RAP-NATURAL GAS PRICES". It can be seen in the exhibit that some of FPL's price forecasts for "non-firm" gas are not explained, such as the [redacted] per MMBtu average difference between gas prices at Transco Station 85 and FGT non-firm (sic) for the next 40 years (with some seasonal variations). FPL also projects that the price of gas at Transco Station 85 will average [redacted] per MMBtu less than the price at the Destin Pipeline not in this record mentioned the fragility of rising shale gas production in the real world of volatile gas prices and international competition. The nature of shale gas well production is somewhat unique. Reports of 50 percent production declines in the first year of shale well operations tell us that continued, aggressive levels of drilling are essential to maintaining production levels from these kinds of resources. In the past nine months, the U.S. rig count has fallen from a peak of 1,606 drilling rigs in September 2008 to just 685 as of June 11, 2009 (Baker Hughes website), as gas prices have fallen. A continuation for another 2-3 years of this drilling deficit without a major increase in field prices would suggest strongly that the current historical levels of increase in shale gas supplies cannot be sustained. We find little discussion of these kinds of risks in FPL's materials.

- Offshore supply risks. A key part of FPL's rationale for receiving gas into the combined Company E/FES system at Transco Station 85 is that Station 85 is not located along the Gulf Coast, thus it would contribute to supply security and avoid hurricane outages of the kind that took place in 2005. Here again, FPL's analysis is unsystematic and general, especially in light of the [redacted] commitment electricity ratepayers are being asked to finance. In fact, gas supplies at a number of onshore Gulf locations were sharply reduced immediately following hurricanes Katrina and Rita, but then rebounded shortly afterward, precisely because rising onshore production was quickly able to replace much of the reduction in offshore production. Exhibit BSA-3 shows how gas supplies in FGT Zone 3 rebounded within days following Hurricanes Rita and Katrina. Quick supply recovery at this and other onshore Gulf Coast pooling points took place because the pipeline grid in the Gulf region is highly and increasingly interconnected, thus enabling considerable volumes of onshore gas tend to migrate to major points along the Gulf Coast. This means that one needn't necessarily "escape" to Transco 85 to avoid Gulf hurricane outages; indeed, the history of the region's destructive hurricanes suggests that Station

<u>***FPL's Inconsistent Rate Presentation***</u>

Q. What are the alternative proposals that FPL has compared in information it submitted in this proceeding?

A. FPL has placed information into this record concerning two pipeline alternatives to supply incremental gas to the Cape Canaveral and Riviera energy stations. These alternatives are (1) the combined Company E/FES system, consisting of Company E's 360-mile interstate pipeline originating at Transco Station 85 plus FPL's proposed 279-mile intrastate FES pipeline, or (2) a modification to FGT's "Company B" proposal to deliver gas from Transco Station 85 along Transco's Mobile Bay Lateral to the interconnection with FGT's pipeline at Citronelle, Alabama, plus capacity expansion along the existing FGT pipeline sufficient to serve the same end markets.

Q. Has FPL offered in this proceeding internally consistent assumptions about pipeline rates for the foregoing alternatives?

A. No, it has not. FPL has offered a rate comparison that can only be described as apples-to-oranges.

Q. Please explain.

A. In presenting rates for its own intrastate pipeline, FPL has offered a declining 40-year rate schedule, but when alluding to interstate pipeline rates FPL has used a flat rate proposed by the pipeline (Company B or E, as the case may be) and held that constant for 40 years. More specifically, FPL has offered a 40-year declining rate schedule for the FES pipeline proper, i.e., its own intrastate portion of the proposed combined Company E/FES system. This rate in the initial year of service is $1.32 per MMBtu, declining down to $.21 per MMBtu in the 40th year. FPL has then taken as a 40-year constant the proposal of Company E to charge a flat rate of [redacted] per MMBtu for the latter's [redacted] pipeline to move gas from Transco Station 85 to FGT Station 16. I understand that Company E did propose to price its transportation service for a rate of [redacted] MMBtu, but FPL has not offered any explanatory or further supportive analysis regarding Company E's rate or how sustainable it is, how expansions will be priced, or what other shippers elsewhere may be required to help sponsor the [redacted] investment requirement. Consequently, this Commission has no way to analyze or determine the risks associated with Company E's offer, e.g., rate adjustment risks if some of the assumptions that underpin that rate are not sustainable.

For the FGT/Company B proposal, FPL has likewise assumed a flat rate of $1.75 (which is actually equal to $1.68 per MMBtu in FGT's March 18, 2009 proposal) as fixed number for 40 years. FPL has then assumed that another $.20 per MMBtu would have to be added to Company B's proposed rate in order to secure transportation along Transco's Mobile Bay Lateral from Station 85 to FGT's proposed receipt point at Citronelle, AL (see Exhibit HCS-2). Review of the FERC's approval of Transco's expansion of the Mobile Bay Lateral, however, indicates the likelihood of a far lower incremental rate of $.09 per MMBtu (see Exhibit MTL-7, page 7). Transco indicated in its Open Season to expand the Mobil Bay Lateral in January 2009 by 550,000 Mcf per day with rolled-in rate treatment, i.e., $.09 per MMBtu (a copy of Transco's January 22, 2009 announcement is attached as Exhibit BSA-4).

Q. What is the consequence of trying to look at pipeline rates this way?

A. FPL's comparison unfairly tips the results toward its own proposal. In Exhibit BSA-5, I compare the way FPL's proposed rate, if levelized for 20 years and then added to its never-decreasing version of the Company E rate, would compare against a never-decreasing version of the FGT/Company B proposal, as extended to Transco Station 85. By this logic, FPL would have us believe that the combined Company E/FES system would cost electricity ratepayers in Florida only [redacted] more than FGT/Company B's proposal, as extended, all things equal.

Q. What is wrong with the conclusion that the combined Company E/FES system would cost electricity ratepayers in Florida only [redacted] more than Company B's proposal, as extended to Transco Station 85?

A. First, there are significantly different assumptions of demand associated with the calculation of these rates. In the Company E/FES calculation, FPL assumes full utilization of 600,000 Mcf/day of capacity from day 1 of the system operation, while their own testimony indicates they only expect to require 400,000 Mcf/day of capacity initially. As such, if the Company E/FES proposal is adjusted to reflect utilization of the lower volumes at a level of 400,000 Mcf/day, the rate would be [redacted] higher that the rate under the FGT proposal, both from Station 85. Moreover, on its face, the idea that Florida's electricity ratepayers face only a relatively small difference in transportation rates between the Combined Company E/FES system versus the FGT/Company B alternative is preposterous because the initial capital investment requirement for the combined Company E/FES proposal is [redacted], as described above, while the comparable capital cost of the March 18, 2009 version of FGT/Company B's proposal is about $1.0 billion, albeit for a 400,000 Mcf/day expansion that more closely matches the stated need.

Q. Would the proposed combined Company E/FES system, including the Company E pipeline and the FES intrastate pipeline, provide the most cost-effective source of natural gas supply, transport and delivery?

A. No, this is not the case. Moreover, even if the combined Company E/FES system were competitive with the FGT/Company B proposal – which it is not – the rate information supplied by FPL treats interstate versus intrastate pipeline capacity costs in an inconsistent way, ignorant of the risks and other factors that I have described above, thus rendering impossible a fair, balanced comparison.

is generally used by the State's gas industry, then it should be structured, operated and regulated as a stand-alone commercial entity, not as an appendage of power generating stations.

Conclusion

Q. Will the proposed Combined Company E/FES system improve the economics of natural gas transmission within Florida to assure the economic well-being of the public?

A. No, in my opinion it would not, and FPL has not offered compelling or convincing information that tells us it would. The proposed FES/Company E pipeline system would cost [redacted], $1.6 billion of which would be charged directly to Florida's electricity ratepayers, with no corresponding benefit that could not be provided at a lower cost by alternative systems – same source, same destinations.

Q. Do you have any final recommendations for the Commission?

A. My recommendations are as outlined above. In particular, it is critical that the FPSC have before it the information necessary to evaluate the kinds of risks I discussed in this direct testimony – including risks of upstream supply acquisition that could be needed at Station 85, rate risks to electricity consumers of all components of the proposed Company E/FES pipeline, risks inherent in allowing FPL to greatly overbuild capacity, and risks that will arise by bundling a very long distance gas pipeline into its electric rate base. In short, the Commission needs to weigh the need for the FES pipeline against a range of options and pipeline configurations that may be considerably less costly and less risky to Florida's electricity ratepayers and the public at large.

Q. Does this conclude your direct testimony?

A. Yes, it does.

EXHIBIT BSA-2 IS CONFIDENTIAL

(15 pages)

COMPARISON OF COMBINED COMPANY E/FES PROPOSAL VERSUS COMPANY B PROPOSAL
(BOTH ASSUMED TO ORIGINATE AT TRANSCO STATION 85), $/MMBU

	FES PIPELINE BASE CASE RATES	COMPANY E PROPOSED RATES	COMPANY E/FES RATE	COMPANY B PROPOSED RATE	MOBILE BAY LATERAL RATE	COMBINED COMPANY B RATE FROM STATION 85
2014	$1.32	[redacted]	[redacted]	1.68	0.09	1.77
2015	$1.27			1.68	0.09	1.77
2016	$1.22			1.68	0.09	1.77
2017	$1.17			1.68	0.09	1.77
2018	$1.13			1.68	0.09	1.77
2019	$1.08			1.68	0.09	1.77
2020	$1.04			1.68	0.09	1.77
2021	$1.00			1.68	0.09	1.77
2022	$0.96			1.68	0.09	1.77
2023	$0.82			1.68	0.09	1.77
2024	$0.75			1.68	0.09	1.77
2025	$0.74			1.68	0.09	1.77
2026	$0.60			1.68	0.09	1.77
2027	$0.57			1.68	0.09	1.77
2028	$0.54			1.68	0.09	1.77
2029	$0.52			1.68	0.09	1.77
2030	$0.50			1.68	0.09	1.77
2031	$0.49			1.68	0.09	1.77
2032	$0.47			1.68	0.09	1.77
2033	$0.46			1.68	0.09	1.77
2034	$0.44			1.68	0.09	1.77
2035	$0.43			1.68	0.09	1.77
2036	$0.41			1.68	0.09	1.77
2037	$0.40			1.68	0.09	1.77
2038	$0.38			1.68	0.09	1.77
2039	$0.37			1.68	0.09	1.77
2040	$0.35			1.68	0.09	1.77

2041	$0.34	[redacted]	[redacted]	1.68	0.09	1.77
2042	$0.33	[redacted]	[redacted]	1.68	0.09	1.77
2043	$0.32	[redacted]	[redacted]	1.68	0.09	1.77
2044	$0.30	[redacted]	[redacted]	1.68	0.09	1.77
2045	$0.29	[redacted]	[redacted]	1.68	0.09	1.77
2046	$0.28	[redacted]	[redacted]	1.68	0.09	1.77
2047	$0.27	[redacted]	[redacted]	1.68	0.09	1.77
2048	$0.26	[redacted]	[redacted]	1.68	0.09	1.77
2049	$0.25	[redacted]	[redacted]	1.68	0.09	1.77
2050	$0.24	[redacted]	[redacted]	1.68	0.09	1.77
2051	$0.23	[redacted]	[redacted]	1.68	0.09	1.77
2052	$0.22	[redacted]	[redacted]	1.68	0.09	1.77
2053	$0.21	[redacted]	[redacted]	1.68	0.09	1.77
20-YEAR LEVELIZED RATE	$0.96	[redacted]	[redacted]	$1.68	$0.09	$1.77

SYSTEM COMPARISON - 100% LOAD FACTOR RATES

COMPANY B FROM STA. 85	$1.77
COMBINED E/FES	[redacted]

SYSTEM COMPARISON - RATES IF 400,000 MCF/DAY IS TRANSPORTED

COMPANY B FROM STA. 85	$1.77
COMBINED E/FES	[redacted]

REFERENCES

FES PROPOSED RATES FROM EXHIBIT HCS-2, PAGES 2-10.
COMPANY B AND E RATES FROM COMPANY PROPOSALS.
MOBILE BAY RATE FROM FERC APPROVAL, EXHIBIT MTL-7, FOOTNOTE 15, PAGE 7.
DISCOUNT RATE OF 8.35% EQUALS FPL'S COMBINED COST OF CAPITAL, FROM EXHIBIT JEE-9.