Exhibit No. DCG-1

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Florida Gas Transmission Company, LLC) Docket No. RP10-21-000

Prepared Direct and Answering Testimony of
PATRICK R. CROWLEY

on behalf of

Florida Cities
Peoples Gas System, a Division of Tampa Electric Company
Tampa Electric Company
(Depreciation Customer Group)

April 27, 2010
Washington, DC

Prepared Direct and Answering Testimony of
Patrick R. Crowley

Executive Summary

Mr. Crowley's prepared and direct and answering testimony presents his analysis and recommendations regarding the proper and adequate depreciation rates applicable to the Florida Gas Transmission Company, LLC (FGT) natural gas pipeline system. FGT proposes to use the depreciation rates agreed to in the settlement of FGT's last rate case in Docket No. RP04-12. Mr. Crowley, on behalf of the Depreciation Customer Group, recommends the following transmission plant depreciation rates:

Non-Incremental Onshore Transmission Facilities:	1.40 %
Incremental Facilities:	1.55 %
Phase VII Incremental Facilities:	2.25 %

See Exhibit No. DCG-25.

Mr. Crowley's testimony develops these transmission plant depreciation rates. In Parts I through III, Mr. Crowley provides an introduction of himself, his testimony, an explanation of depreciation theory in general, and a brief background of the FGT system. *See* Exhibit No. DCG-1 at pp. 9 – 22. Part IV of Mr. Crowley's testimony describes FGT's as-filed depreciation rates and plant balances in this proceeding and how the plant balances differed between the as-filed levels and the end-of-test-period compliance filing. *See* Exhibit No. DCG-1 at pp. 22 – 25.

Mr. Crowley then explains in Part V a background of average service lives and the impact of interim retirements. These concepts are then applied to FGT in this proceeding. Exhibit No. DCG-1 at pp. 25 – 31, Exhibit No. DCG-8, and Exhibit No. DCG-9. Part VI of Mr. Mr. Crowley's testimony provides an explanation of his proposed remaining life truncation period for FGT. *See* Exhibit No. DCG-1 at pp. 31 – 49. In this part, Mr. Crowley describes FGT's traditional resource area, reserve life for natural gas supplies in the United States Gulf Coast area, estimates of proved reserves and annual production, potential gas reserves, shale gas reserves, and competition for reserves in the Gulf Coast area. A number of exhibits are relied upon by Mr. Crowley, including various maps (Exhibit Nos. DCG-4, DCG-10 through -14, and DCG-20), an FGT customer presentation (Exhibit No. DCG-5), information regarding FGT's interconnections with other natural gas storage and transmission providers (Exhibit Nos. DCG-6 and -7), information regarding the number and costs of natural gas wells drilled (Exhibit Nos. DCG-17 through -19), and information regarding natural gas reserves and annual production (Exhibit Nos. DCG-15, DCG-16, and DCG-21 through -23). Mr. Crowley uses this information to explain why he recommends a truncation period in this proceeding based upon a reserve life estimate of 50 years. *See* Exhibit No. DCG-1 at pp. 46 – 43.

In Part VII, Mr. Crowley explains the use of survivor curves and their application in this proceeding through the input of service lives, average age of plant in service, interim retirements and truncation periods as part of the derivation of depreciation rates. *See* Exhibit No. DCG-1 at pp. 45 – 50. Exhibit No. DCG-24 provides examples of the Iowa Survivor Curves explained by Mr. Crowley.

Part VIII provides the depreciation rates recommended by Mr. Crowley by deriving the remaining depreciable life of the pipeline facilities involving the combination a calculation of correct plant balances and average age of plant in service by account, selection of an average service life by account, determination of the remaining economic life, and selection of the appropriate survivor curve to estimate interim retirements. These elements result in an average remaining life of 34 years for Non-incremental transmission facilities and 40 years for Incremental and Phase VII transmission facilities and the depreciation rates as stated above. *See* Exhibit No. DCG-1 at pp. 55 – 56. Mr. Crowley's calculations of his recommended depreciation rates are contained in Exhibit No. DCG-25. The impact of these recommendations on the cost of service is a reduction in the depreciation expense from the as-filed figures by FGT of approximately $10.9 million for Non-Incremental transmission facilities and approximately $19.8 million for Incremental transmission facilities. *See* Exhibit No. DCG-1 at p. 56.

Mr. Crowley concludes his testimony with Part IX where he addresses Asset

Retirement Obligations and Negative Salvage. *See* Exhibit No. DCG-1 at pp. 56 - 57. Based upon a data response provided in Exhibit No. DCG-27, Mr. Crowley does not include any adjustment for negative salvage costs in this proceeding. Mr. Crowley also explains his adjustment to the Asset Retirement Obligation amortizations. These adjustments, as proposed in Exhibit No. DCG-28, result in a reduction in the annual amount required of shippers.

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List of Exhibits

Exhibit	Descriptive Title	Protected?
DCG-1	Crowley Direct and Answering Testimony in RP10-21	No
DCG-2	Crowley Curriculum Vitae	No
DCG-3	List of Crowley Testimony	No
DCG-4	FGT System Map	No
DCG-5	FGT Customer Meeting Presentations	No
DCG-6	FGT Interconnecting Pipelines	No
DCG-7	Gas Receipts by Major Interconnecting Carrier	No
DCG-8	Retirement Activity in Major Accounts	No
DCG-9	Discovery Response to STAFF-FGT-DEP-1.5	No
DCG-10	U.S. Lower 48 Conventional Gas Production Areas	No
DCG-11	Potential Gas Committee Gulf Coast Area Maps	No
DCG-12	Texas Railroad Districts Map	No
DCG-13	U.S. Pipeline Network Map	No
DCG-14	U.S. Pipeline Expansion Trend Maps	No
DCG-15	Reserve Life Estimate: 2008	No
DCG-16	Gulf Coast Proved Reserves & Annual Production	No
DCG-17	U.S. Exploratory & Developmental Wells Drilled	No
DCG-18	U.S. Drilling Cost per Well	No
DCG-19	U.S. Gas Wells Drilled	No

DCG-20	U.S. Shale Gas Plays	No
DCG-21	Shale Gas Proved Reserves & Annual Production	No
DCG-22	U.S. Lower 48 Proved Reserves & Annual Production	No
DCG-23	Wyoming & Colorado Proved Reserves & Annual Production	No
DCG-24	R2 & R4 Iowa Survivor Curves	No
DCG-25	Depreciation Rate Calculations	No
DCG-26	Discovery Response to STAFF-FGT-DEP-1.30	No
DCG-27	Discovery Response to PGS-TECO-FGT 9.25	No
DCG-28	Asset Retirement Obligation Amortizations	No

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(Depreciation Customer Group)

PART I INTRODUCTION AND OVERVIEW

Q. Please state your name and business address.

A. My name is Patrick R. Crowley. My business address is 630 E Street, Northeast, Washington, D.C. 20002.

Q. By whom are you employed?

A. I am a consultant in regulatory energy matters with my own firm, Crowley Energy Consulting. I provide regulatory energy litigation support and expert analysis in the oil and gas pipeline industries and electric transmission industry.

Q. On whose behalf are you presenting your testimony in this matter?

A. My testimony is presented on behalf of the Depreciation Customer Group (DCG), which is made up of Florida Cities (comprising of JEA, the Orlando Utilities Commission, Lakeland Electric, the City of Tallahassee, the City of Gainesville d/b/a Gainesville Regional Utilities and Florida Gas Utility, a Florida inter-local agency whose membership presently consists of more than twenty municipally-owned electric and/or gas utilities), Peoples Gas System, a Division of Tampa Electric Company, and Tampa Electric Company.

Q. What is the purpose of your testimony?

A. The purpose of this testimony is to present my analysis and recommendations regarding the proper and adequate depreciation rates applicable to the Florida Gas Transmission Company, LLC (FGT) natural gas pipeline system.

Q. Please describe your higher education degrees and employment history.

A. I was graduated from DePaul University in Chicago, Illinois with a Bachelor of Arts degree in economics in 1976 and with a Master of Arts degree in economics in 1978, with a concentration in mathematical economics. Upon graduation from DePaul University in 1978 I joined the Chicago, Rock Island & Pacific Railroad for a short time before I joined the Federal Energy Regulatory Commission ("FERC" or "Commission") in 1979 where I was employed for 28 years. I retired to form my own consulting firm in February 2007. My curriculum vitae is provided in Exhibit No. DCG-2.

Q. Please summarize your experience as a regulatory energy economist.

A. I began work at FERC in 1979 as an Industry Economist in the Pipeline Rates Division of the Office of Pipeline Rates. As an expert witness with the Trial Staff gas and oil litigation team from 1979 to 1992, I prepared pipeline depreciation studies, long-term forecasts of crude oil and natural gas reserves and production, mortality studies of plant retirements, cost behavior studies for pipeline facilities, and Mcf-mile studies. From 1992 through 1994, I worked on the operational aspects of the Order No. 436 service restructuring of Texas Eastern Transmission, LP and was the FERC Staff team leader for the restructuring of Tennessee Gas Pipeline Company. From 1994 through 1998, I worked on the advisory side of the Commission where I prepared reports for Commission orders regarding proposals for revised tariff terms, new services, rate designs, and tariff rates, and a wide variety of utility reports and cost studies. In 1998, I returned to the litigation side of the Commission where I worked on electric utility and natural gas and oil pipeline rate cases, complaint cases, and show cause orders.

Q. Have you filed testimony before the FERC?

A. Yes, I have filed testimony before FERC in numerous dockets, as reflected on Exhibit No. DCG-3.

Q. Have you filed testimony previously on depreciation matters?

A. Yes, as a member of the FERC Litigation Staff I filed depreciation testimony in the following natural gas pipeline rate cases:

Natural Gas Pipeline Company of America, Docket No. RP93-36-000;
Williams Natural Gas Company, Docket No. RP91-152;
Tarpon Transmission Company, Docket No. RP92-164-00;
Mississippi River Transmission Corporation, RP89-248 and RP90-75;
U-T Offshore System, Docket No. RP89-38-000;
High Island Offshore System, Docket No. RP89-37-000;
Transcontinental Gas Pipe Line Corporation, Docket No. RP87-7-000;
Southwest Gas Storage Company, Docket No. RP89-60-000;

Paiute Pipeline Company, Docket No. RP88-227-000;
Natural Gas Pipeline Company of America, Docket No. RP88-209-000;
Sea Robin Pipeline Company, Docket No. RP88-181-000;
Pacific Gas Transmission Company, Docket No. RP87-62-000;
National Fuel Gas Supply Corporation, Docket No. RP86-136-000;
Tarpon Transmission Company, Docket No. RP84-82-000; and
Black Marlin Pipeline Company, Docket No. RP81-67-000.

Q. In addition to your written testimony in this case, are you sponsoring any supporting exhibits?

A. Yes. Please see the List of Exhibits in my testimony, Exhibit No. DCG-1 at pp. 7- 8.

Q. Were your testimony and exhibits prepared by you or under your direction?

A. Yes.

Q. Please briefly describe the analysis you performed in connection with your testimony in this proceeding.

A. My analysis in this proceeding included: a review of the FGT October 1, 2009 rate case filing; review of responses by FGT to discovery requests by the intervenors and Staff; analysis of the plant balances and retirement experience for the FGT system; development of survivor curve analysis to project future interim retirements on the FGT system; assessment of the long term natural gas resources available to the FGT system; and development of proper and adequate depreciation rates for the FGT system.

Q. What depreciation rates does FGT currently use and what is the implied remaining life suggested by those rates?

A. FGT’s current depreciation rates for transmission plant are 2.13% for Non-Incremental facilities, and 2.50% for Incremental facilities (inclusive of Phase VII Expansion plant). At FGT’s current net plant ratio, the implied remaining life is approximately 24 years for both the Non-Incremental and Incremental facilities, as more fully explained in Part IV of this testimony.

Q. What do the results of your analysis indicate in regard to the proper and adequate annual depreciation rates and expense for FGT?

A. My analysis and recommendation is that the proper and adequate annual depreciation rates for FGT should be: 1.40% for Non-Incremental transmission facilities; 1.55% for Incremental transmission facilities; and 2.25% for Phase VII Expansion transmission facilities. Together these recommendations result in a decrease of approximately $30 million from FGT's as-filed transmission plant depreciation expense proposal of approximately $99 million (Exhibit No. FGT-19 Statement A.1 and FGT-25, Statement A.2). I recommend that the general plant depreciation rates for both the Non-Incremental and Incremental facilities reflect the rates currently used for the Non-Incremental facilities. I also recommend the immediate transfer of funds collected from shippers for the amortization of the Asset Retirement Obligation (ARO) on the Matagorda Offshore Pipeline System to an ARO investment fund, and a reduction of the annual ARO amortization of approximately $26,000 per year.

Q. Please summarize the derivation of your recommended depreciation rates.

A. Depreciation expenses are intended to recover the pipeline's investment in plant and equipment over the useful life of the facilities. In the case of assets whose useful life is dependent upon natural resources, as more fully explained below, the depreciation rates rest upon the underlying resource life expectancy. In this case, that resource base is the long-term natural gas reserve recoverability of the United States Gulf Coast. Recent advances in drilling technology have significantly increased the estimates of recoverable natural gas reserves such that, using the traditional measure of reserve life estimate for the United States lower-48 states, the current life expectancy for United States natural gas reserves is 66 years. The Gulf Coast reserve life is currently 64 years as more fully explained in Part VI of this testimony.

The continuing advancement of drilling sciences and technology renders the 64-year reserve-life estimate a conservative figure. Nonetheless, I used an even more conservative economic truncation period of 50 years for my depreciation rate calculations, as more fully explained in Part VI (b) of this testimony. Using 50 years as the underlying foundation for the depreciation rates, the application of standard depreciation rate practices, such as the assessment of retirement patterns and application of survivor curve methodology to project long-term interim retirements, results in an average remaining useful life of approximately 34 years for FGT's Non-Incremental facilities and 40 years for FGT's Incremental facilities and Phase VII Expansion facilities. When applied to the individual asset accounts, these remaining useful life factors result in average depreciation rates of 1.40% for Non-Incremental transmission plant facilities, 1.55% for Incremental transmission plant facilities, and 2.25% for Phase VII Expansion of Incremental transmission facilities.

PART II DEPRECIATION THEORY

Q. What is depreciation?

A. Depreciation is a term used in accounting, economics, and finance to convey the inherent loss of value in an entity's assets over time and the associated allocation of capital costs over some defined period. Depreciation concerns itself with the allocation of original cost over time.

Q. Please explain the concept behind the allocation of capital costs.

A. Capital costs are those costs incurred to acquire plant and equipment that will be used over several accounting periods to facilitate the provision of an entity's goods and services. The anticipated longevity of the asset is, in a sense, the purchase of future services from the asset; depreciation is the expensing of those future services. When investors purchase assets they expect to get their money back and earn a profit on that investment: the return ***of*** investment as well as return ***on*** the investment. In order to get an accurate assessment of their economic activities, entities need to accurately match expenses with the revenue generated. Deducting the costs of operations and the capital investment costs from the revenue stream reveals the profitability of the enterprise. Depreciation and amortization are the means by which capital costs are allocated over time to reflect the concept that capital costs contribute to profitability in all periods. The accurate estimation of depreciation ensures that the claimed annual profitability of the enterprise is neither understated nor overstated.

Q. Please explain the importance of time in depreciation analysis.

A. The allocation of cost over time is the essence of depreciation. The cost of capital should be allocated among all the time periods for which that capital is used and useful. A long depreciable life for assets owned by a short-lived entity would not serve the purpose of matching costs with revenue generated. The resulting lower depreciation expense might suggest high annual profitability when, in fact, total costs had not been covered by the annual revenues. In the end the investors would not have recovered their investment.

Similarly, a short depreciable life for assets owned by a long-lived entity would also fail to accurately match costs with revenues. The resulting higher depreciation expense might suggest lower annual profitability when, in fact, total actual costs had been covered by the annual revenues. In the end, these investors would have over-recovered their investment. In an industry where customers are considered more or less captive, or the service provided is considered a public good, fairness to the customers requires that the customers' annual contribution to the cost of operating the enterprise is close to the actual cost of the operating the enterprise, including a reasonable return of investment, neither overstating nor understating the true cost of providing the service. The tools used in depreciation analysis derive the pattern of plant mortality and survivorship that are the foundation for allocating capital costs across the time periods in which those costs contribute to generating revenues. The accurate measurement of those patterns allows for the accurate allocation of capital costs.

Q. How does the Commission define depreciation?

A. The Commission's Uniform System of Accounts for Natural Gas Companies defines depreciation as:

> [T]he loss in service value not restored by current maintenance, incurred in connection with the consumption or prospective retirement of gas plant in the course of service from causes which are known to be in current operation and against which the utility is not protected by insurance. Among the causes to be given consideration are wear and tear, decay, action of the elements, inadequacy, obsolescence, changes in the art, changes in the demand and requirements of public authorities, and in the case of natural gas companies, the exhaustion of natural resources.

18 C.F.R. Part 201, Definitions, 12.B (2009).

Q. How does the underlying resource base factor into the estimation of depreciation?

A. The determination of the useful life of industrial property is often dependent upon an underlying non-renewable resource base, the exhaustion of which sets the outer limits of the assets' depreciable lives. In the case of oil and natural gas properties, the useful life of some assets is limited to the reserve life of the oil or natural gas anticipated to flow through the assets, including "proved reserves" known to be accessible at any given time, plus the "future reserves" that can be reasonably expected to become proved reserves at some point.

Q. How do plant retirements affect depreciation?

A. If depreciation were an exact science, units of plant and equipment would be retired in the same year that the associated depreciation accruals reached 100% of the investment in that plant. However, some plant will be retired prior to the end of the average service life of like-property; other units may be retired in favor of greater capacity units or the loss of need for any units. If the units are retired prior to the end of the average service life upon which the depreciation rates rest, the associated depreciation accruals will not have fully recovered the invested cost in the assets. To ensure the recovery of invested capital, plant retirements are deemed to be fully recovered at the time of retirement, and the original cost of the investment is deducted from both the plant-in-service balance and the accumulated reserve for depreciation balance. Removing the full original cost from the depreciation reserve disproportionately affects the reserve, causing the ratio of the reserve to plant-in-service to decrease. The result is a higher net un-depreciated plant. In essence, the un-depreciated portion of the retired plant is transferred to other assets to be recovered over the remaining useful life of the remaining assets.

Q. Is it important to periodically re-examine depreciation rates?

A. Yes. The standard depreciation tools, as used in my analysis here, facilitate the analysis of an entity’s situation based on a snapshot of conditions affecting the depreciable life of the entity’s assets at the time of the review. Depreciation tools such as survivor curve analysis measure the effects of normal wear and tear, as well as routine retirement patterns. These tools are not intended to track major changes in the pipeline’s plant or business operations. For example, there have been three substantial changes that affect depreciation of FGT's pipeline system. These changes require adjustments to FGT's depreciation rates even though FGT has not sought to change the rates in this proceeding. First, FGT’s substantial increases in plant investment to expand system capacity would be expected to lead to a higher depreciation rate (and expense) to recover the additional capital costs, assuming no corresponding increase in life expectancy of FGT's system. Second, the substantial retirements of plant and equipment that FGT has experienced would, as discussed earlier, give rise to the need to raise depreciation rates to recover the retired plant dollars assuming the life expectancy of FGT's system has not changed. Third, significant growth in estimated recoverable natural gas reserves has changed the probable remaining economic life of FGT’s pipeline assets, leading to a reduction in the depreciation rates. How these elements fit together requires a new depreciation study. The old snapshot of FGT’s depreciation requirements no longer fits the facts and circumstances surrounding FGT's current configuration and access to natural gas supplies. A new depreciation study will facilitate accurate allocation of capital costs over the remaining useful life of FGT's property.

Q. What are the basic depreciation methodologies?

A. There are several methods of matching depreciation accruals to the useful life of assets. The methods relevant to pipeline accounting and rate making are straight line whole life method, straight line average remaining life method, unit of production method, and levelized method. The *whole life method* generally applies to plant with high turn-over and replacement rates such as general plant, and allows for several generations of plant to be added and retired without re-evaluating the appropriateness of depreciation rates with each generation. The *average remaining life method* is used for plant with low turn-over rates but with substantial plant additions and retirements related to plant expansion or changes in resource needs, all of which lead to the need to re-evaluate the depreciation status to assure accurate recovery of capital. The *unit of production method* ties accruals directly to the exhaustion of the underlying resources, and is used most often for production facilities. *Levelized* depreciation is a method used to reduce the "rate shock" of new pipelines where straight line depreciation and return on rate base add up to prohibitively high revenue requirements. Levelized rates treat the return of and on investment in the same manner as a home mortgage with the principal (depreciation) recovery deferred to later years.

Q. What depreciation methodology did you use for FGT’s transmission plant?

A. I used the straight line average remaining life method for FGT’s transmission plant to accommodate the substantial changes in plant additions, retirements, and reserve life estimate, each of which alter the annual depreciation accrual needed to accurately spread the remaining capital costs over the useful life of FGT's property.

Q. Please describe the steps you took to arrive at your depreciation rate recommendations.

A. The calculation of depreciation rates involves several steps that focus on the actual life expectancy of the plant in service and derive an accrual rate that should match the return of investment capital with the actual useful lives of the property. Step 1 is to determine the actual depreciable plant to be recovered. As will be seen below, the FGT plant balances reflected in the filing are substantially in excess of the plant actually in service at the end of the test period (February 28, 2010). Step 2 is to determine the average physical service lives of the plant and equipment. Depreciation accruals should be set to recover 100% of the invested capital, with the physical life expectancy of the assets setting the outer limit of depreciable life. Step 3 is to determine the remaining life of the resources that underlie the need for the assets in the first place. To the extent the natural gas reserves are depleted before the potential physical life of the plant is reached, the lower life span sets the controlling limit for depreciation rate calculations. Step 4 is to set the truncation date, the date at which the plant should be fully recovered. If some extraneous factor such as a change of business plans indicates the cessation of operation of the assets in question, again the lower life span estimate becomes the controlling figure. Step 5 is to evaluate the impact of interim retirements on the accruals prior to the truncation date. Step 6 is to divide the net un-depreciated plant by the truncation life span estimate to arrive at the depreciation expense, and then divide the expense by the amount of depreciable plant in service to arrive at the depreciation rate. Step 7 is to determine the estimated net salvage cost to ensure that costs of removal and gain or loss on the sale of the assets retired are incorporated into the development of depreciation accruals.

Q. Please review the "remaining life" terms.

A. The depreciable lives of an entity's assets are bound by three life expectancy estimates: 1) the average physical life expectancy of the various classes of property; 2) the average remaining life of the natural gas reserves supporting the need for the assets; and 3) the average remaining depreciable life, which takes into account interim retirements.

PART III FGT'S PIPELINE SYSTEM

Q. Please describe FGT's system insofar as it relates to the matters set for hearing in this docket.

A. In 1958 FGT's predecessor, the Houston Corporation, proposed to build a pipeline from the Gulf Coast production areas of Texas and Louisiana to markets in peninsular Florida. The initial system would have daily capacity of 282,000 Mcf/day, comprise 2,712 miles of pipe, and cost $161,000,000 to build. FGT currently operates a 5,000 mile system with access to abundant natural gas resources, and with a capacity of 2.3 Bcf/day to over 250 delivery points. As depicted on the system map in Exhibit No. DCG-4, FGT's system stretches from Refugio County, Texas, to Dade County in southern-most Florida. As described in PowerPoint slides presented at customer meetings in October 2008 (reproduced in Exhibit No. DCG-5), FGT is very well situated to serve the needs of its customers. FGT is by far the largest natural gas pipeline in Florida, has completed several major expansion projects, and has a major expansion (Phase VIII) under construction. In its presentation materials, FGT boasts of interconnects to 14 natural gas pipeline and storage facilities. Even more interconnections are shown in FGT's response to the discovery request Staff-FGT-DEP-1.15 where FGT lists interconnections with approximately 30 natural gas pipeline and storage companies along the Gulf Coast giving

FGT access to virtually all the natural gas resources of the Gulf Coast. These pipelines are listed in Exhibit No. DCG-6. The top seven interconnecting pipelines in terms of 2008 supplies delivered to FGT's system are shown in Exhibit No. DCG-7.

The FGT system is composed of two geographic divisions: the Western Division, which is all plant and equipment west of the Alabama/Florida state line; and the Market Area, which is all plant and equipment in the State of Florida. FGT is separated into two systems for rate design purposes. The Non-Incremental facilities system is comprised of the original pipeline system and all plant expansions through the Phase II Expansion in 1995. The Incremental facilities system is comprised of virtually all plant expansion projects after 1995, beginning with the Phase III Expansion through the Phase VI Expansion competed in 2003. FGT is seeking to roll the most recent Phase VII Expansion into the Incremental facilities costs. The massive Phase VIII Expansion, approved in Docket No. CP09-17, is under construction.

PART IV FGT PLANT BALANCES AND DEPRECIATION RATES

Q. Please describe FGT's rate filing as it relates to depreciation expense.

A. In its filing, FGT proposed a general rate increase pursuant to Section 4 of the Natural Gas Act and Part 154 of the Commission's regulations for existing services, and changes to certain terms and conditions of service, with an effective date of November 1, 2009, for its proposed tariff sheets and an end-of-test-period date of February 28, 2010. FGT proposed to retain its existing depreciation rates with no changes. FGT's current depreciation rates for transmission plant are 2.13% for the Non-Incremental facilities and 2.50% for the Incremental facilities. Exhibit No. FGT-19, Statement A.1 of FGT's rate filing reflects total annual depreciation expense, incorporating general and intangible plant, onshore and offshore transmission, asset retirement obligations and negative salvage of $34,362,966 for the Non-Incremental facilities. Exhibit No. FGT-25, Statement A.2 of the filing reflects an annual depreciation expense of $65,326,745 for the Incremental facilities.

Q. FGT's as-filed cost of service included depreciation expense figures for Non-Incremental and Incremental onshore transmission facilities. What depreciation rate and implied remaining life do these figures suggest?

A. FGT's filing retained the existing depreciation rates, but applied the rates to plant balances much greater than the plant that was actually in service at the time of the rate filing. FGT's end-of-test-period compliance filing indicated the total plant was approximately $104.7 million less than the plant balances reflected in the filing as reflected in a comparison of Statements C.1 and C.2 of the original filing and the April 14, 2010, Compliance filing.

	As Filed (05/31/2009)	Compliance Filing (02/28/2010)	Difference
Exhibit FGT-21 Statement C.1 Non-Incremental	$ 1,441,707,991	$ 1,357,156,928	$ 84,551,063
Exhibit FGT-27 Statement C.2 Incremental	$ 2,051,385,754	$ 2,031,203,259	$ 20,182,495
Total	$ 3,493,093,745	$ 3,388,360,187	$ 104,733,558

At the as-filed depreciation rates, the difference would result in $2.6 million of excess annual depreciation expense. The implied remaining life at these depreciation expense levels for the actual depreciable plant in service at the end of the test period is shown in the table below:

	Non-Inc Trans Plt	Inc Trans Plt	Phase VII
Trans Plt	$ 1,279,929,360	$ 1,955,935,222	$ 61,886,147
Acc Res Depr	$ 619,163,489	$ 742,886,421	$ 5,588,644
Net Plt	$ 660,765,871	$ 1,213,048,801	$ 56,297,503
Depr Exp as filed	$ 29,191,858	$51,161,213	
Implied Life	22.6	24.8	
De facto Rate	2.28%	2.54%	

A comparison of the claimed versus actual depreciation rates can be derived by dividing the annual depreciation expense included in the cost of service by the depreciable base from the as-filed cost of service and by the actual February 28, 2010, depreciable transmission plant. This simple calculation reveals a ***de facto*** depreciation rate increase from 2.13% to 2.28% for Non-Incremental transmission plant facilities and from 2.50% to 2.54% for Incremental transmission plant facilities.

Q. What do you mean by a *de facto* depreciation rate increase?

A. By incorporating a depreciation expense predicated on a higher than actual rate base, FGT incorporates into its tariff rates an effective depreciation rate higher than that reflected on its books. Booked depreciation accruals will continue to reflect the stated depreciation rate times the actual depreciable plant balance, but the rates paid by ratepayers will reflect expenses greater than appropriate for FGT's depreciation needs. Changes in depreciable plant between rate cases will lead to a divergence between booked depreciation expenses and amounts collected from ratepayers derived from depreciation recommendations, which is why periodic review of depreciation rates is necessary.

Q. How were FGT's current rates derived?

A. FGT's current depreciation rates are the result of a settlement in the last FGT general rate case before FERC in Docket No. RP04-12.

Q. Does FGT have depreciable offshore plant?

A. FGT has investment in some offshore facilities within its Non-Incremental facilities' umbrella; however, these facilities are shown in Exhibit FGT-22, Statement D.1 as fully depreciated.

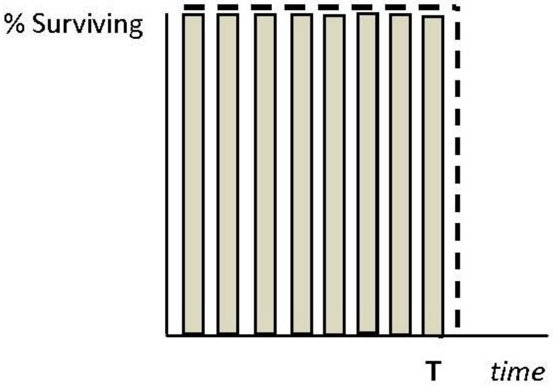
PART V INTERIM RETIREMENTS AND AVERAGE SERVICE LIVES

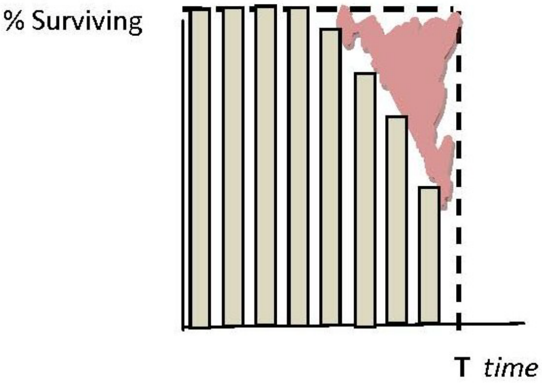
Q. Please explain the concept of average service life.

A. The physical plant of large industrial entities like pipelines is made up of thousands of units of property. For example, the pipeline itself is not one long pipe. Rather, it consists of thousands of 20 to 40 foot sections of pipe installed over decades as the system expanded, or as portions of the system were replaced due to damage or wear and tear. The usefulness and longevity of each section of pipe depends on the conditions associated with its use. Eventually, the retirement experience begins to reveal how long an average section of pipe can be expected to remain in service. The same type of information can be gleaned for each group of property used in providing the pipeline service.

Q. What is the significance of determining the average service life of plant and equipment?

A. For our purposes, knowing the average service life of plant and equipment allows for an accommodation in the depreciation rate derivation to reflect plant retired prior to the truncation period for recovering all the capital investment. As noted above in the discussion about the effect of retirements on depreciation accounting, these interim retirements are considered fully recovered and the full original cost of the unit of property is deducted from the accumulated reserve for depreciation. If interim retirements are not taken into consideration in deriving the average remaining life of plant, the depreciation rate will have under-recovered the plant at the truncation date. This concept is illustrated in the diagram below.





The application of a straight line depreciation rate to the annual rate base builds the depreciation reserves through annual accruals in equal installments, as shown in the vertical bars on the left. By the truncation date **T,** the plant should be fully accrued. However, if the rate base is declining because of interim retirements, the annual accruals will not add up to the full amount needed for recovery by the **T** truncation date, leaving a shortfall shown as filled in at the right.

Q. Did you review the interim retirement experience for FGT’s system?

A. Yes. In response to discovery request STAFF-FGT-DEP-1.9 requesting FGT's plant additions by vintage year by account, surviving plant balances by account, and annual retirement experience by vintage year by account, FGT provided its FERC Form 2 Annual Report for the years 1984 through 2008. Because it is both voluminous and publicly available, I have not reproduced the FGT response to this discovery request as an exhibit here. The data provided by FGT reflects total annual retirements from all plant vintages rather than vintage retirements. Under this format, it is not possible to develop actual experience survivor curves. However, as more fully discussed in Part VII, survivor curve tools can still be used to derive interim retirement estimates.

Q. What do you mean by "actual experience"?

A. Actual experience survivor curves would generate a unique plant mortality pattern based on actual vintage retirement data rather than representative patterns found in the Iowa Curves series.

Q. What does the annual retirement data indicate?

A. The annual retirement data provided in response to discovery requests STAFF-FGT-DEP-1.5, attached as Exhibit No. DCG-9, and STAFF-FGT-DEP-1.9 indicate a very low level of retirements in general. For example, in Account 367 – Mains, which is the largest account by far, the pattern of annual retirements as a percentage of total plant balance in that account is on average less than four-tenths of a percent. In Exhibit No. DCG-8, I have combined the data from the FERC Form 2 for Accounts 366-Structures and improvements, 367-Mains, 368-Compressor station equipment, and 369-Measuring and regulating station equipment. I have also provided graphs illustrating the annual retirements as a ratio of the previous year's end-of-year balance. Together these accounts make up 96% of the total plant in service. The FERC Form 2 does not break out the data by Non-Incremental or Incremental facilities. All four accounts show very low retirement experience with average retirement rates of under one percent annually. Where there are bands of increased retirement activity, they occur in years that FGT was undergoing major expansions. For example, the Phase III Expansion began in 1995; the plant data for Mains show substantial plant additions and increased retirements for the years 1995, 1996, and 1997. The Phase IV Expansion began in 2001. The plant activity indicates increased retirements in 2000, 2001, and 2002, and substantial additions in 2001 and 2002. This suggests retirements made in order to install greater capacity plant and equipment. The plant activity schedules show major plant adjustments and transfers in those expansion periods as well. The data also shows that over 85% of the current plant investment occurred since the onset of the 1995 Phase III Expansion.

Q. How do you interpret the annual retirement data?

A. The plant activity schedules indicate that the pipeline plant and equipment is a very long-lived investment, which is what would be expected of heavy duty industrial plant intended to transport hazardous material over long distances for a long time without failure. The retirement and transfer data suggest periodic major overhauls related to substantial system upgrades rather than a pattern of regular retirement activity. The Mains account reflects ***transfers*** since 1995 amounting to $81 million, while retirements since 1995 add up to $91 million. For the Compressor Station Equipment, transfers since 1995 make up one-third of the plant taken out of service. These transfers reflect plant investment shifting from one account to another or one operating division to another, not plant taken out of service. Transfers out and adjustments may reduce the surviving balances in any given vintage year’s installation, but represent plant that continues to have a useful life in some other account and should not be incorporated into the service life evaluation as if they were retirements. Unfortunately, we do not know the vintage year with which the transfers and adjustments should be associated. Taken all together the plant activity data reflect industrial plant with very long average service lives. FGT’s oldest plant, the 1950 Mains installations, are now 50-years-old with approximately 77% of the original installation still in service.

Q. What does the data indicate about the accruals of older plant?

A. FGT’s response to discovery request STAFF-FGT-DEP-1.5 (attached as Exhibit No. DCG-9) provides the vintage surviving plant balances and associated accumulated reserve for depreciation by account. In every account, all the plant installed prior to 1981 is fully depreciated. Therefore, there is no concern that the interim retirements from those vintages could be under-accrued by the truncation date. The only plant being depreciated is the plant that was installed after 1981, which makes the average age of un-depreciated plant quite young, approximately 10-years-old.

Q. Please list the average service lives for the transmission accounts.

A. I selected the average service lives by account as listed below:

Account 365.2	Rights-of-way	65 years
Account 366.1	Compressor station structures	65 years
Account 366.2	Measuring and regulating station structures	65 years
Account 366.3	Other structures	65 years
Account 367	Mains	65 years
Account 368	Compressor station equipment	40 years
Account 369	Measuring and regulating station equipment	40 years
Account 370	Communication equipment	40 years
Account 371	Other equipment	30 years

Q. Please summarize your reasons for selecting these average service lives.

A. I selected these average service lives to reflect several aspects of FGT's plant and experience, as follows: 1) the plant is industrial property intended to transport hazardous material for a long time without failure; 2) the annual retirement experience reflects very low levels of routine retirements; 3) periods of increased retirements are associated with major plant expansions, suggesting that the plant did not wear out but rather was replaced with greater capacity plant; 4) transfers and adjustments indicate plant removed from service in the particular account but re-used elsewhere; 5) the vintaged surviving plant balances indicate that even the oldest installations have substantial proportions of surviving plant after 50 years; and 6) the average age of un-depreciated plant is under ten years, so that the estimated average service life being contemplated reflects new plant and equipment, not decades old equipment.

Q. Please describe the nature of the plant in these accounts.

A. The type of plant or equipment in each account is described by the Commission's Uniform System of Accounts, 18 C.F.R. Part 201, Gas Plant Instructions (2009). For example, Account 366-Structures and improvements includes the structures that house the compressors and measuring equipment. Account 368-Compressor station equipment includes long-lived plant such as gas lines, tanks, gauges, lockers, electric system equipment, and laboratory equipment. Account 369-Measuring and regulating station equipment includes boilers, meters, odorizers, control regulators, piping, fittings, and wiring. Account 370-Communication equipment includes radios, telephones and microwave systems.

Q. Should the retirements associated with major expansions be incorporated into the adjustment for interim retirements in deriving depreciation rates?

A. No. The interim retirement adjustment is intended for plant for which obsolescence is a normal part of its life span experience. For example, desktop computer equipment may have a 20-year potential life span but the advances in technology render most computer equipment obsolete and virtually useless in under five years. The turn-over rate for plant prone to obsolescence is part of the management plan for those assets. Retirements associated with major expansions are not routine, nor are they part of the annual management plan for those types of assets. Major expansion-related retirements come about because the underlying business has changed. The appropriate time and place to adjust depreciation rates to take major expansion-related retirements into account is in periodic reviews of the depreciation rates, for instance during a rate case.

Q. How do you measure the size of the future interim retirements?

A. Depreciation analysis is a forward looking exercise using the past as a guide. Through the use of plant mortality analysis, patterns of retirements can be discerned that tend to follow known mathematical trajectories, known as survivor curves. Overlaying a truncation date on the survivor curve allows one to measure the area identified as the interim retirements percentage. Survivor curves will be discussed in Part VII of my testimony below.

PART VI REMAINING LIFE TRUNCATION PERIOD

Q. What topics will you cover in this part of your testimony?

A. Determining the truncation period for pipeline facilities involves weighing several factors that affect the remaining economic life of the pipeline. In this part of my testimony I will discuss: a) the FGT traditional resource area and FGT's physical access to resources; b) the Gulf Coast reserve life; c) estimates of proved reserves and annual production; d) estimates of future reserves; e) shale gas reserve growth; f) competition for future reserves; and g) the 35-year truncation horizon.

a. <u>FGT Traditional Resource Area</u>

Q. What is FGT's traditional resource area?

A. FGT's traditional resource area is the northern portion of the Gulf of Mexico along the coasts of Texas, Louisiana, and Alabama, historically one of the most productive natural gas resource areas of the nation, as seen in the United States Department of Energy, Energy Information Administration (DOE/EIA) map of conventional natural gas fields in the U.S. Lower 48 states in Exhibit No. DCG-10. The Gulf Coast includes the following Petroleum Administration District areas:

Texas Railroad District 2	Louisiana North
Texas Railroad District 3	Louisiana South Onshore
Texas Railroad District 4	Louisiana State offshore
Texas State Offshore	Louisiana Federal Offshore
Texas Federal Offshore	Alabama

These areas can be seen in the maps in Exhibit No. DCG-11, which reflects the Potential Gas Committee Gulf Coast designations, and Exhibit No. DCG-12, which shows the Texas Railroad Districts.

Q. Please describe the area.

A. The Gulf Coast remains the dominant producing region in the country despite extensive prior exploration and production activity. The area abounds in gathering pipeline systems, offshore platforms, trunk line pipelines, and interconnections. The numerous pipelines that converge on the area can be seen in the DOE/EIA U.S. Natural Gas Pipeline Network map in Exhibit No. DCG-13. The relative share of national gas supply coming out of the Gulf Coast can be sensed by the pipeline capacity charts in Exhibit No. DCG-14. The Gulf Coast reservoirs are, in general, highly porous and have favorable permeability, which makes them capable of delivering large volumes at any given well site. This characteristic has made the Gulf Coast the focus of previous exploration and production that, together with extensions of known fields through developmental drilling, make the Gulf Coast a proven producing area. Moreover, the area is still viewed as holding significant new fields yet to be discovered in deeper waters and which are considered to be the early stages of exploration. Four new pipeline systems have been built to access these reserves: Independence Trail Natural Gas Pipeline (1.0 Bcf per day); Discovery Gas Transmission LLC (0.6 Bcf per day); Destin Pipeline Co., LLC (1.0 Bcf per day); and Nautilus Pipeline Co., LLC (0.6 Bcf per day), each of which originate far offshore.

Q. Please describe the pipeline network in the Gulf Coast area.

A. The pipeline infrastructure in the Gulf Coast region is extensive and highly integrated, with a number of hubs reflecting a robust natural gas market-place. Natural gas production from the Gulf Coast flows generally east toward the Gulf and Atlantic states, or north to the Midwest and northeast United States, as illustrated in Exhibit No. DCG-14, a trend map for U.S. pipeline expansion. Several large interstate pipeline systems operate in the Gulf of Mexico bringing natural gas to the integrated pipeline network through interconnections with offshore platforms and producing fields. Two major natural gas pipelines serve the State of Florida: FGT and Gulfstream Natural Gas System, LLC ("Gulfstream"). Where as FGT stretches across the onshore tier of Gulf Coast states, Gulfstream transports natural gas supplies from the Mobile Bay area of Alabama across the Gulf of Mexico to west central Florida.

Q. Is FGT well situated in regard to access to natural gas supplies?

A. FGT is extremely well situated in regard to access to natural gas supplies. Its pipeline stretches along almost the entire coast of the Gulf of Mexico (Exhibit No. DCG-4) with interconnections with about 30 natural gas pipeline and storage facilities (Exhibit No. DCG-6) that, in turn, have access to virtually all the natural gas supplies in the Gulf. FGT touts its excellent position in its customer meeting materials (Exhibit No. DCG-5), noting in particular its interconnections with Transcontinental Gas Pipe Line, LLC (Transco), Destin, Transco’s Mobile Bay lateral from Station 85, and El Paso Corporation’s Gulf LNG Energy, LLC terminal at Pascagoula, Mississippi.

b. <u>Gulf Coast Natural Gas Reserve Life</u>

Q. Have you reviewed the natural gas supplies accessible by FGT in the Gulf Coast area?

A. Yes.

Q. What do you conclude from your review?

A. I have concluded that the natural gas reserves in the Gulf Coast are abundant and sufficient to support at least a 50 year reserve life for depreciation purposes. The Gulf Coast area proved reserves, potential reserves and estimated future annual production discussed below are shown in Exhibit No. DCG-15.

Q. What is the basis for your conclusion?

A. The remaining economic life of pipelines that rely on specific resource areas is traditionally based on the reserve life of the resources in that area, *i.e.*, the estimated remaining producible reserves to be found in those areas divided by the estimated annual production from the same areas.

Q. What are the remaining producible reserves for the Gulf Coast area?

A. The estimated remaining producible reserves for the Gulf Coast are made up of proven reserves and potential future reserves yet to be discovered. As shown in Exhibit No. DCG-15, the DOE/EIA estimate of proven natural gas reserves for the Gulf Coast is 40.5 Tcf. Future reserves of recoverable Gulf Coast natural gas, as estimated by the Potential Gas Committee ("PGC") and reported in its 2008 biennial report, is 332.9 Tcf. The PGC figure includes probable and possible categories of future gas reserves. Together the proven, probable, and possible gas supplies in the Gulf Coast amount to 373.5 Tcf.

Q. What is your estimate of the annual production for the Gulf Coast area?

A. Annual production from the Gulf Coast area fields in 2008, the most recent data reported by DOE/EIA, was 5.8 Tcf (Exhibit No. DCG-16, p. 3). Dividing the remaining recoverable reserves by the 2008 production level would suggest a reserve life of over 64 years (Exhibit No. DCG-16, pp. 4 and 6). In light of the current recession, I would expect the 2009 and 2010 Gulf Coast annual production figures to be lower. However, in the long run over which the depreciation rate is calculated, I expect Gulf Coast production to return to levels in the range achieved over the last decade. The average annual production level for the 2000 – 2008 period was 7.5 Tcf. Exhibit No. DCG-16, pp. 4 - 7 shows the Gulf Coast annual reserve and production figures from 1984 through

2008. At the 7.5 Tcf level the Gulf Coast reserve life would be 49.5 years. I used a 50-year reserve life for the truncation period in the depreciation calculations.

c. Estimates of Proved Reserves and Annual Production

Q. What are proved reserves?

A. Proved reserves are the estimated quantities of natural gas that current analysis of geologic and engineering data demonstrate with reasonable certainty to be recoverable in the future from known oil and gas reservoirs under existing economic and operating conditions. Reservoirs are considered “proved” when they demonstrate the ability to produce natural gas, either by actual production or by conclusive formation tests; for proved reserves the existence and quantity of gas have been confirmed by testing. Estimates of proved reserves are therefore limited to those reserves of natural gas that have been established by drilling and do not reflect potential resources of natural gas that may be discovered as a result of future exploratory drilling.

Q. What does the recent trend in Gulf Coast natural gas proved reserves reflect?

A. The annual estimate of proved reserves in the Gulf Coast has been declining over the last 15 years, as reflected in the data available from the DOE/EIA databases. Annual estimated proved reserves for each of the Gulf Coast production areas can be seen in Exhibit No. DCG-16, pp. 1-3. From a high point of 56.7 Tcf in 1997, proved reserves declined to 40.5 Tcf in 2008.

Q. What does the recent trend in Gulf Coast natural gas production reflect?

A. The DOE/EIA annual estimate of production of Gulf Coast natural gas reserves has also declined over the last 15 years, as reflected in the data available from the DOE/EIA databases. Annual estimated production for each of the Gulf Coast production areas can also be seen in Exhibit No. DCG-16, p. 1. Gulf Coast annual production has declined from a high of 9.47 Tcf in 1997 to 5.81 Tcf in 2008. In light of the current recession 2009 and 2010 Gulf Coast production figures may be lower still; however, I expect Gulf Coast production to return to levels in the range found over the last decade. The average annual production level for the 2000 – 2008 period was 7.5 Tcf.

Q. What does the trend in productivity per well for the Gulf Coast reflect?

A. Gulf Coast natural gas productivity on a per well basis has declined, as would be expected in an area of developed fields. Most if not all of the very large fields in shallower waters have been discovered and their more permeable area resources produced. As the size of newly discovered fields and reservoirs shrinks, and the tighter sands in the older fields are developed, the natural gas productivity on a per well basis would be expected to shrink as well.

Q. Has the rate of finding natural gas resources improved?

A. Yes, the success ratio of drilled wells has improved dramatically. Although productivity of each well has fallen generally, the accuracy of drilling has improved substantially. Advancements in drilling technology have increased the success ratio for both developmental drilling and exploratory drilling, as reflected in the chart on Exhibit No. DCG-17, page 4. As shown, the success ratio of exploratory wells has grown from approximately 10% in 1970 to 60% in 2008. More importantly, these advancements allow producers to focus drilling efforts on development wells rather than exploratory wells, bringing probable and possible gas reserves into the proved category. In other words, as reflected in Exhibit No. DCG-17, pp. 1 - 2, development of a gas field entails fewer exploratory wells and fewer non-productive (dry) development wells. These trends can be seen in the charts depicting successful and dry exploratory drilling in the U.S. since 1975, and successful and dry developmental drilling in the U.S. since 1975 (Exhibit No. DCG-17, pp. 2 - 3). The more efficient that drilling activities become, the more that producers are able to find producible reserves, in a sense allowing for a “just in time” inventory of proved reserves. Further, the dramatic increase in the cost of drilling natural gas wells, as reflected in Exhibit No. DCG-18, mitigates against drilling in less certain areas. Producers will seek to drill in known areas, expanding known formations with greater likelihood of success. This trend is borne out in the data illustrated in the graph shown in Exhibit No. DCG-19. The graph reflects four categories of drilling: exploratory wells, dry exploratory wells, developmental wells, and dry developmental wells. The high numbers of dry exploratory and development wells of the late 1970s and early 1980s have tapered off, while successful developmental drilling has increased dramatically.

Q. Please comment on the downward trend in proved reserves for FGT’s traditional supply area.

A. I am not overly concerned about the downward trend in current proved Gulf Coast reserves because the proved reserve estimate is a figure that is replenished as drilling in and around existing fields takes place. According to the Independent Petroleum Association of Mountain States, half of the natural gas consumed today is produced from wells drilled within the last 3.5 years. The best place to find natural gas is near where it has already been found. Until reservoirs near existing producing formations are tested or begin production themselves, they may lie still as “probable” reserves pending the need to develop them. Reserves become “proved” when the field goes into production or sufficient engineering data demonstrates the existence of producible reserves. As noted above, more accurate drilling makes each well more likely to find producible reserves. Estimates of proved reserves will reflect additions (minus production) as development drilling expands the parameters of known formations, converting probable reserves into proved reserves. The recent dramatic increase in potential natural gas, as more fully described below, provides significant opportunity for future growth in proved reserves.

d. Potential Gas Reserves

Q. What are potential reserves?

A. Potential reserves are the as yet undiscovered gas reserves and some discovered reserves not included in proved reserve estimates. There are three categories of potential resources: probable, possible, and speculative, which are differentiated by the availability and reliability of engineering information.

Q. What are probable reserves?

A. Probable reserves are estimated quantities of natural gas that, based on geologic evidence from projections of proved reserves, can reasonably be expected to exist and be recoverable under existing economic and operating conditions. Probable reserves are associated with known fields and are the most reliable of potential supplies. Well established engineering information supports the estimation of resources in this category. Probable reserves include estimated future extensions of existing producing pools that have not been confirmed through testing.

Q. What are possible reserves?

A. Possible reserves are the estimated natural gas reserves believed to exist outside known fields but associated with a productive formation in a productive province. Possible reserves are the projected resources expected to be developed as new fields are discovered in known formations but in less well explored areas.

Q. Have you included speculative reserves in your analysis?

A. No. Speculative reserves are those thought to exist in new fields in new formations that have not been sufficiently tested to determine potential productivity.

Q. What is the Potential Gas Committee?

A. The PGC consists of approximately 145 individuals from the natural gas industry, including government and academic institutions, who volunteer biennially to assess the size and location of the nation's natural gas resource base using both public and private company data sources. The subcommittee that determines the remaining gas resource base consists of individuals who make their living exploring for and developing gas in the basins that they assess. Each regional assessment is formally peer-reviewed by other PGC members to ensure the estimates are accurate and credible.

Q. How are PGC estimates reported?

A. The PGC reports natural gas resource estimates biennially in certain categories: Probable, Possible and Speculative. For each category, minimum, most likely, and maximum resource volumes are estimated for each of 89 geological provinces. Mean values are then calculated by statistical aggregation of the minimum, most likely and maximum values for each category of potential resource. This procedure allows for direct comparison of PGC's estimates with gas resource assessments made by other organizations.

Q. Are potential gas estimates based on current technology?

A. The PGC's estimates of potential gas supplies reflect reserves that can be recovered under current or foreseeable technology assuming reasonable economic incentives. The PGC does not make assumptions about when the resources may be developed or the specific price for the gas produced.

Q. Are future reserves required to be considered in setting depreciation rates?

A. Yes. The United States Court of Appeals for the District of Columbia Circuit in *Memphis Light, Gas and Water Division v. Federal Power Commission* provided guidance for the Commission on that question:

> In order to be "just and adequate" a reserve life depreciation rate must be based upon the useful life of the **particular property** involved. We therefore believe that it is the Commission's obligation to make some reasoned estimate of the useful life of the property here involved even though to do so would require an estimate of future reserves. We realize that such a prognostication would necessarily be only an estimate, but at least the Commission would thereby attempt to ascertain how the gas shortage has affected the useful life of this property.

504 F.2nd 225, 235 (D.C. Cir. 1974) (footnote omitted) (emphasis in original).

Q. Has the Commission specifically tied the economic life of a pipeline to the estimated natural gas supplies anticipated to be transported by the pipeline?

A. Yes, the Commission has affirmed that the estimate of total gas reserves should be the foundation upon which the economic life of a pipeline system rests. In Opinion No. 441, *Trunkline Gas Company*, the Commission upheld the Administrative Law Judge's ("ALJ") ruling about basing the truncation period on the remaining natural gas reserves when it agreed with the ALJ's finding that:

> …for depreciation purposes the question of the economic or useful life of the facilities turns on the length of time that an adequate supply of gas is anticipated to flow through those facilities, because it is generally accepted that the supply of natural gas will run out before the facilities wear out.

90 FERC ¶ 61,017 at 61,050 (2000).

Hence, for depreciation purposes the question of economic life or lives of the conduits or facilities turns on the length of time than an adequate supply is anticipated to flow through these facilities.

Q. Did you include liquefied natural gas ("LNG") supplies in your analysis?

A. No. Because LNG is transported in tankers, it can come from various sources, making world-wide LNG production capacity available to the Gulf Coast pipelines. I was not sure how to estimate those supplies. Given the abundant gas supplies in the Gulf Coast, I believe LNG supplies would augment annual volumes but am not certain they would increase the lifespan expectancy of the pipeline.

e. <u>Shale Gas Reserves</u>

Q. Does the PGC estimate of potential gas reserves include shale gas?

A. Yes. The inclusion of shale gas in the probable and possible categories of potential natural gas is an example of reserves “moving up” as technology made recovery possible. The PGC has included shale gas in its estimates of traditional potential reserves since 1988. Although shale gas has been produced for about 150 years, it has been produced in small quantities. The advancements in geological sciences, engineering technology, and play specific strategies has led to substantial growth in both the estimated shale reserves and the production of shale gas reserves.

Q. Why is shale gas included in “traditional” natural gas reserve estimates?

A. Shale is included in traditional natural gas reserves because it is found in traditional natural gas rock formations, albeit in tight sands. The existence of large amounts of shale gas in natural gas formations throughout the United States has been known since the late 1970s. However, the technology needed to recover or even test the quantities of natural gas recoverable from low permeability tight sands did not exist until recently. Consequently, the PGC classified shale gas reserves as speculative. Shale gas reserves are considered "unconventional" because they exist in tighter formations than "conventional" drilling can access. The term "traditional" in reference to natural gas supplies appeared in 1986 when the PGC created the term to distinguish "traditional" rock formation gas supplies from coalbed gas supplies.

Q. Where are the shale gas deposits located in the Gulf Coast area?

A. Shale gas is present across much of the continental United States and the Gulf Coast. Although there are many shale gas basins, most of the exploration, testing, and production has been concentrated in six major shale basins, including the Haynesville Basin in northern Louisiana/east Texas, and the Texas-Louisiana-Mississippi Salt Basin, which surrounds Haynesville and under-lays northern Louisiana, southern Mississippi and the panhandle of Alabama. The major shale gas formations are shown on the map in Exhibit No. DCG-20.

Q. What is the shale gas share of current proved reserves and production of the Gulf Coast area?

A. Shale gas development is still in its infancy. Despite 150 years of experience with shale formations, only recently has technology provided the means to exploit the resources economically. DOE/EIA began publishing separate information regarding shale gas proved reserves and annual production levels in 2007. At this point, shale gas represents only a small share of traditional proved reserves and annual production. The DOE/EIA data is shown in Exhibit No. DCG-21.

f. Competition for Future Reserves

Q. You noted earlier that there is an extensive pipeline network in place to carry Gulf Coast production to the north and east; does that threaten FGT's prospects for access to Gulf Coast supplies in the long run?

A. Although there is an extensive pipeline network in place to move Gulf Coast reserves north or east, there are other factors working in FGT's favor that may dampen the competitive demand for Gulf Coast resources: 1) natural gas reserves and production are increasing in areas outside of the Gulf Coast, especially in the Rocky Mountains; and 2) pipeline transportation links are expanding to move Rocky Mountain and Canadian gas supplies to the U.S. Midwest and East Coast. For example, TransCanada's Bison Pipeline received FERC approval on April 9, 2010 to transport natural gas from the Powder River Basin to the Midwest.

Q. How do proved reserves and annual production estimates of other producing regions affect the FGT resource base?

A. The declining trends in the Gulf Coast proved reserves and annual production data are not echoed in the figures for the U.S. Lower 48 proved reserves and annual production. As shown in Exhibit No. DCG-22, the DOE/EIA data indicate growing estimates of proved reserves and annual production. The data reflects the maturing of the older Gulf Coast fields and the development of new fields in younger areas such as the Rocky Mountains. The growth in other areas overshadows the declines in the Gulf Coast, for a total U.S. Lower 48 picture of growth in both proved reserves and annual production. Proved reserves and annual production data for Wyoming and Colorado can be seen in Exhibit

No. DCG-23. The growth in these areas provides entities vying for Gulf Coast resources with alternatives for acquiring natural gas resources. Given alternative sources, some Midwest and East Coast contenders for Gulf Coast supplies will become more price sensitive. Where the pipeline configuration is less advantageous for attaching non-Gulf Coast gas reserves, shippers are less able to respond to alternate resource area opportunities. As non-FGT shippers reduce purchases of the Gulf Coast supplies, FGT shippers have greater assurance that they can acquire and access Gulf Coast supplies.

Q. How does the expanding national pipeline network affect the FGT resource area?

A. In conjunction with the increasing natural gas reserves and production in the Rocky Mountains and other areas, the expansion of the interstate pipeline network provides the transportation route by which the added Rocky Mountain resources move to eastern markets. The maps in Exhibit No. DCG-14 illustrate the recent expansion in pipeline capacity and projected increases in capacity for 2010 and 2011. The greater the capacity out of alternative resource areas, the less reliant contenders are on the Gulf Coast supplies, affording FGT shippers greater assurance of obtaining the Gulf Coast supplies.

Q. What is FGT's competitive position in the State of Florida?

A. Population growth in the State of Florida is expected to grow in the future, along with economic growth and the demand for electric generation. Until recently, FGT was the only source of natural gas available to the Florida’s natural gas shippers and customers. The completion of the Gulfstream pipeline system means that FGT is no longer the sole provider. Yet, FGT continues to expand its own system. Between 2000 and 2007, FGT installed 1.2 Bcf per day of new capacity, and is currently adding another 1.1 Bcf per day of new capacity in connection with its Phase VIII and the Mobile Bay Lateral expansions. The latter expansion is still going through an environmental review. FGT customer meeting materials (Exhibit No. DCG-5) reflect a strongly positive outlook by FGT management concerning the pipeline's future in Florida.

g. <u>The 35-Year Horizon</u>

Q. What is the typical truncation period used in pipeline depreciation studies?

A. Depreciation studies traditionally base the truncation period on the reserve life for the area from which the pipeline sources most of its natural gas supplies. Depreciation studies performed in the 1980s and 1990s typically used a truncation period ranging from 20 to 35 years depending on the area.

Q. Please explain why your recommendation departs from this 20 to 35-year truncation period.

A. My analysis and recommendation follow the traditional approach of basing the truncation period on the reserve life estimates. For pipelines with the broadest resource base, the truncation period used in depreciation studies has been consistent with the US natural gas reserve life, which has typically been around 30 to 35 years for the 1980s, 1990s, and 2000s. This consistency in the US natural gas reserve life led to an informal "custom" of using 35 years as the truncation period, regardless of the actual reserve life. However, what is traditional about the 35-year truncation horizon is the underlying ***methodology*** that arrives at 35 years rather than the number itself. The definition of depreciation found in the Code of Federal Regulations, as noted in Part II above, includes "exhaustion of natural resources" as the final criteria in determining proper depreciation rates. 18 C.F.R.

Part 201, Definitions, 12.B (2009). The Commission has emphasized that natural gas supply is the ***single most important factor*** in determining a pipeline's remaining useful life. The 35-year horizon is not just some comfortable place to stop the forecast, but rather represents the exhaustion of resources expected to flow through the pipeline. I have relied on the traditional methodology of dividing recoverable natural gas reserves by the annual production rate. The result of applying this traditional methodology is a 50-year remaining life of the natural gas reserves.

Q. Have you applied the traditional methodology to the past estimates of recoverable reserves and annual production?

A. Yes. The traditional methodology of dividing the recoverable reserves (proved, probable, and possible) by the estimated annual production produces a 30 to 35-year truncation horizon for the US Lower 48 for the quarter century prior to 2006. The steady state of recoverable reserves for both the US Lower 48 and the Gulf Coast is reflected in the graph on page 4 of Exhibit No. DCG-16. From 1990 through 2004, reserve life estimates, calculated in the traditional manner, remained remarkably steady. The proven and potential natural gas reserve estimates and annual production levels from which the charts were drawn are on pages 6 and 7 of the exhibit. This 30 to 35-year reserve life represented the exhaustion of gas reserves available to major pipelines, as required by the Commission's definition of the causes to be considered in determining proper depreciation rates. The 2006 and 2008 growth in potential reserves follows the PGC tradition of estimating natural gas supplies based on current technology and economic conditions. When applied to the Gulf Coast area, the same methodology produced a reserve life generally in the 20 to 25-year range through most of the 1990s and 2000s.

Now, however, like the figures for the Lower 48, the Gulf Coast reserve life has increased and is 64 years.

Q. Has the Commission addressed the truncation period to be used in support of depreciation rates?

A. Yes. The Commission's order regarding appropriate foundations for selection of the truncation period in *Iroquois Gas Transmission System, L.P*. upheld the ALJ's decision finding that figures based on something other than gas reserve estimates would be in error:

> The ALJ found that the record indicates that natural gas supply is the single most important factor in determining a pipeline's remaining useful life…. The ALJ found that a 35 year remaining life projection was just and reasonable for Iroquois. The ALJ stated that while the Staff and Joint Parties' depreciation studies each adequately accounted for non-supply factors affecting remaining useful life, **only Joint Parties' study estimated available supply in an objective fashion. The ALJ stated that Staff witness Pewterbaugh simply relied on a subjective judgment that estimates above 25 years are too speculative.** The ALJ found that Joint Parties' witness Raina, in contrast, relied on the relevant fact that TransCanada's most recent depreciation study produced a 35 year economic life for the pipeline on which Iroquois is dependent for its supply. The ALJ found that Joint Parties' estimate therefore had the dual advantages of being linked directly to Iroquois through the pipeline's upstream conduit and more accurately reflected the vast Canadian reserves which produce Iroquois's gas.

84 FERC ¶ 61,086 at 61,435 (footnote omitted) (*emphasis added*).

The Commission stated that the most important factor for determining depreciation related to gas supply and affirmed the ALJ's decision in *Iroquois* that remaining life estimates based on objective data derived through empirical analysis outweighed subjective judgments. The FERC Litigation Staff's exclusion of almost 30% of the natural gas reserve life was rejected by the Commission. *Id.* at 61,439. Further, the ALJ found that Iroquois shippers were not limited to specific natural gas supplies but rather, through Iroquois, had access to the vast reserves which therefore were a more accurate estimate of the useful life of the pipeline system. *Id.* at 61,435. *Iroquois* occurred during a period in which the Canadian National Energy Board estimated total remaining ultimate supply gas reserves in western Canada at 194 Tcf and annual production was about 5.6 Tcf, resulting in a reserve life of about 35 years. The Staff's selection of a shorter life for its comfort zone was rejected by the ALJ. In the instant docket, a similar abundance of natural gas reserves, based on objective data derived through empirical analysis and analyzed in the traditional manner, leads to a reserve life estimate of 50 years.

PART VII SURVIVOR CURVES

Q. Please explain your consideration of the service lives, average age of plant in service, interim retirements, and truncation periods in deriving depreciation rates.

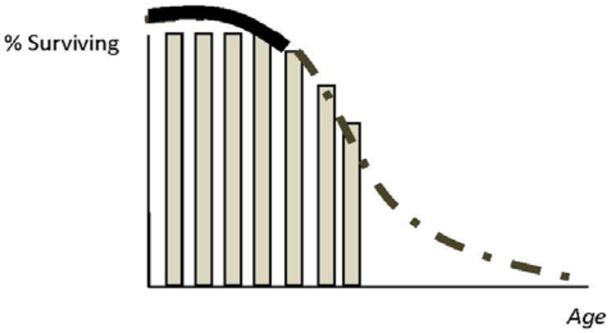
A. Estimated service lives, average age of plant in service, interim retirements, and truncation periods enter into the derivation of depreciation rates through the use of survivor curve methodology. Survivor curves are the end result of actuarial analyses of mortality patterns in populations of things that cease to function, such as industrial property. The curves represent the mathematical formulae derived in the actuarial studies and provide a tool that can assist in forecasting future mortality or retirement patterns.

Q. How does the survivor curve methodology work?

A. The survivor curve methodology starts with the assumption that retirement patterns follow a normal distribution around the median and modes of observations of retirements. The charts of industrial property retirements convert the frequency of retirement observations into percent surviving charts. All the calculations are then performed using figures based on the percent of average service life. Using the average service life estimates and the current average age of plant-in-service by account, the methodology converts the average age into a percentage of the average service life. From there, the methodology calculates the probable life expectancy of the remaining plant, which will be longer than the average service life for the whole of the property, *i.e.*, the subset of plant still surviving will have longer lives than the whole set that includes plant already retired. The second part of survivor curve methodology is to recalculate the survivorship percentages at the truncation year. The difference between the percent surviving in the study year and the percent surviving in the truncation year leads to the level of interim retirements expected to occur prior to the truncation year. The last step converts the percent surviving figures back into average service lives.

Q. How are survivor curves constructed?

A. Survivor curves are constructed through the collection of vintaged surviving plant dollars by year of installation. In other words, for each installation year investment, the percent of that year's plant still surviving in each subsequent year is calculated. The same exercise is performed for every year's installation dollars. In the end, one can calculate the average survivor percentage for all one-year-old plant. The same can be calculated for all two-year old plant, and so on. This process continues until there is no data left to calculate any surviving plant dollars. Where data may be incomplete, the calculated patterns of survivorship can be compared to a standard set of survivor curves, known as Iowa Type Survivor Curves, to complete the retirement curve slope as shown in the diagram below.

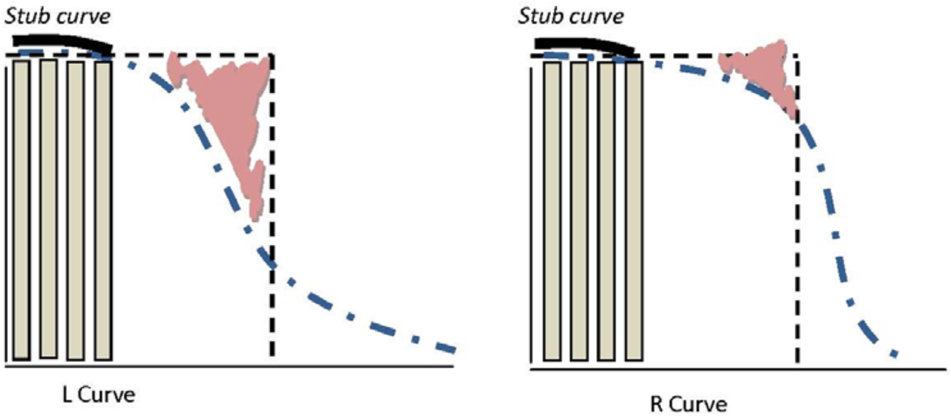


Q. Are there different kinds of Iowa Curves?

A. Yes. Iowa Curves measure the mortality of plant installations; thus, there can only be one direction that the curve can go: down. All mortality curves are downward sloping. The survivor curves are built around the idea of standard distributions of statistical observations, essentially a bell curve representing the pattern of retirements. For survivor curves the pattern is converted from the number of retirements per year (or retirement dollars) into the percent of plant surviving, giving the ski-slope pattern common to survivor curves. As with bell shape curves, there is an ***average*** observation, which is the center point of the area under the curve, and there is *a* ***mode***, or most frequently occurring point. In survivor curves terminology, the **L** curves represent patterns where the mode lies to the ***left*** of the average, *i.e.*, the most frequent retirement age is less than the average age. An **R** curve represents patterns where the mode lies to the ***right*** of the average, *i.e.*, the most frequent retirement age is greater than the average age. Three types of errors may cause the depreciation reserve to be accrued incorrectly: selection of the wrong family of curves ("L" rather than "R"), selection of the wrong average service life (40-year versus 60-year), or selection of the wrong level of curve within the family group (level 2 versus level 4).

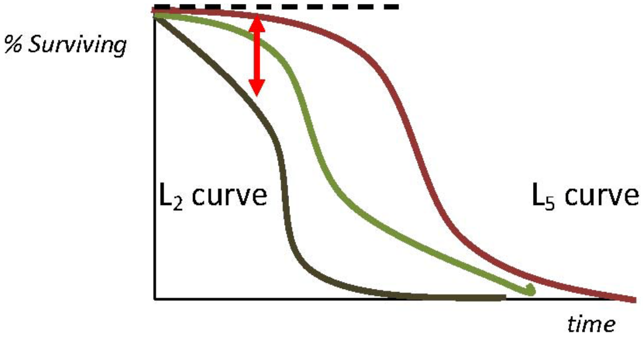
Q. Can the modes make a difference?

A. Yes. Where insufficient data requires reliance on Iowa Curves to complete the stub curves rather than the actual experience derived curve, the choice of type of curve is important. The estimated pattern of retirements will increase or decrease the depreciable plant that may be over-accrued or under-accrued relative to the truncation date. If the L curve better represents the underlying pattern of retirements, a larger adjustment must be made for the interim retirements, as on the left below. If the R curve better fits the pattern, a smaller adjustment would be needed, as on the right below.



Q. Does the number of the curve within a family of curves affect the analysis?

A. Yes. Within each family of curves, the levels from 0 to 5 reflect the level of early retirements for any given age of plant; an L_2 curve will show significant early retirements; an L_5 curve will show almost no early retirements.



An example of the Iowa Curves can be seen in Exhibit No. DCG-24.

Q. What if you do not have sufficient data to construct an entire survivor curve?

A. Where there is insufficient data to develop an entire curve, the calculation can lead to a "stub" curve, which may or may not be long enough to associate with any standard Iowa Curve. Such is the case here. While FGT provided vintage surviving plant balances by account (discovery response to Staff-FGT-DEP-1.5, attached as Exhibit No. DCG-9), FGT did not provide a full history of vintage installation back to the original start of operations in 1959 . In response to requests for vintage installation balances by account, FGT provided its FERC Form 2 back to 1984 (discovery response to STAFF-FGT-DEP-1.9). However, the survivor curve tools can still assist in developing the interim retirement adjustments. Given the average age of the plant in service and reasonable assumptions about the appropriate selection of curves and average service life, the level of interim retirements can be calculated from the standard Iowa Curves data base.

Q. How do survivor curves treat major retirement episodes?

A. Survivor curve analysis is based on the assumption that interim retirements occur in a normal distribution generally represented graphically as a bell shaped curve. The distribution of retirements occurs around the asset type’s average service life so that, given enough time and observations, the retirements will fall into standard patterns that can be predicted with a strong degree of accuracy. Major retirements are neither random nor associated with the asset's average physical service life and, consequently, would tend to skew the results of a survivor curve calculation by creating the appearance of a lower average physical service life. Major retirements, as well as major transfers and adjustments, should be removed from the data before an actuarial survivor curve model is calculated. Major retirements are taken into consideration when periodic depreciation rate re-evaluations are made and the net un-depreciated plant balance can be allocated over the remaining life of the facilities.

Q. What curves did you select for FGT's assets?

A. FGT's very low level of routine transmission plant retirement experience mirrors the **R** shaped curve typically seen in pipeline depreciation studies, *i.e.*, FGT is made up of heavy duty industrial property with high survivorship rates right up to the average service life. **R** curves are found with plant for which there is a high retirement rate soon after the average service life, represented by the steeper sloping **R** shaped Iowa Curve after the average service life point. Within the family of **R** shaped curves, I found the **R4** appeared to better match the FGT retirement experience of high survivorship over long periods of time, unlike the **R2** curves which would represent plant with substantially higher early interim retirements. Examples of R2 and R4 curves are provided in Exhibit No. DCG-24

PART VIII DEPRECIATION RATES

Q. How did you estimate the remaining depreciable life of the FGT facilities?

A. Deriving the remaining depreciable life of the pipeline facilities involves combining the several steps discussed above: 1) calculation of the correct plant balances and average age of plant in service by account from Part IV above; 2) selection of an average service life by account from Part V above; 3) determination of the remaining economic life from Part VI above; and 4) selection of the appropriate survivor curve to estimate interim retirements from Part VII above. The survivor curve methodology described above pulls these elements together into the derivation of an estimated remaining economic life for the pipeline facilities. The result is an average remaining life of 34 years for Non-incremental transmission facilities and 40 years for Incremental and Phase VII transmission facilities.

Q. What is your recommendation in regard to FGT's transmission plant?

A. My recommendation is that the proper and adequate annual depreciation rate for the FGT system should be:

1.40% for Non-Incremental transmission facilities;
1.55% for Incremental transmission facilities; and
2.25% for Phase VII transmission facilities.

The calculations leading to these depreciation rates are shown in Exhibit No. DCG-25.

Q. What is your recommendation in regard to general plant?

A. General plant does not have the same long-lived properties found in transmission plant and has a much higher turnover experience. Using a remaining life methodology would be inappropriate given the long period between depreciation studies. The whole life method better suits property with high turnover rates as part of routine experience. FGT's existing depreciation rates appear to be based on a whole life method whose average service lives appear reasonable.

Q. What is the impact of your depreciation recommendations on the cost of service?

A. The impact of my recommendations on the cost of service is a reduction in the depreciation expense from the as-filed figures of approximately $10.9 million for Non-Incremental transmission facilities and approximately $19.8 million for Incremental transmission facilities.

PART IX ASSET RETIREMENT OBLIGATIONS AND NEGATIVE SALVAGE

Q. How did you treat negative salvage in your depreciation calculations?

A. In its response to STAFF-FGT-DEP-1.30, attached as Exhibit No. DCG-26, and PGS-TECO-FGT 9.25, attached as Exhibit No. DCG-27, FGT reported almost no retirements of offshore facilities and zero cost of removal expenses for the period 2005 through 2008. Absent some demonstration that there is or will be negative salvage costs, I included no adjustment for such in the depreciation calculations. At such time as FGT provides data and/or an analysis of potential negative salvage costs, the depreciation rates could then be reconsidered.

Q. Did you make any adjustments to the Asset Retirement Obligation amortizations?

A. Yes, I did make an adjustment to the ARO amortizations. In FGT's rate filing, Schedule H-2(2).1 shows the derivation of the annual shipper contribution toward the ARO for the Matagorda Offshore Pipeline System (MOPS) and Vermillion Island offshore facilities. The derivation includes a five year "company contribution" of $166,953 toward the ARO investment fund. As noted in footnote 3 of this schedule, the total "company contribution" equals the total negative salvage dollars collected from FGT's shippers through March 2010. Contrary to the column heading, the $834,765 total figure is not a company contribution; rather, this figure reflects amounts already contributed by shippers. FGT has not shown why the interest on those funds should accrue to FGT rather than the ARO investment fund. FGT should be required to transfer the total amount, $834,765, into the ARO investment fund immediately. Adding the sum to the investment fund reduces the amount needed in future contributions by shippers to meet the retirement obligations in the years 2022 and 2030 by $132,000. The result of such a transfer is a reduction in the annual amount required of shippers from $687,283 to $660,900, or $26,383 per year. A comparison of the FGT proposal and my proposal can be seen in Exhibit No. DCG-28.

Q. Does this conclude your prepared direct and answering testimony?

A. Yes.

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Florida Gas Transmission Company, LLC) Docket No. RP10-21-000

AFFIDAVIT OF PATRICK R. CROWLEY

I, Patrick R. Crowley, do hereby declare that under penalty of perjury that I have prepared the foregoing testimony and that the facts set forth therein are true and correct to the best of my knowledge.

P Crowley

April 27, 2010