BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

In Re: Application for Determination of Need for an Intrastate Natural Gas Pipeline by SunShine Pipeline Partners	))))))	Docket No.: 920807-GP Filed: April 12, 1993

DIRECT TESTIMONY

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Q. Please state your name, address and position.

A. My name is Paul R. Carpenter. My business address is 125 Summer Street, Boston, Massachusetts 02110. I am the President of Incentives Research, Inc.

Q. Would you briefly describe Incentives Research, Inc.?

A. Incentives Research provides economic and financial consulting services to public and private sector clients, primarily in the fields of energy markets and industry structure, regulatory policy analysis, financial economics methods, and antitrust.

Q. Please summarize your educational and professional background.

A. I received a Ph.D. in Applied Economics from the Massachusetts Institute of Technology, a M.S. in Management from MIT and a B.A. in Economics from Stanford University. For over ten years I have been involved in research and consulting on matters relating to energy economics and policy, with a particular focus on the natural gas industry. I have testified before Congress, the Courts and before the FERC, state and Canadian provincial regulatory commissions in many of the important cases resulting from the transition to the new regulatory policies that are being applied to the gas pipeline industry. In particular, I have been involved in several cases at the Federal and state levels in which the appropriate regulatory policy toward new pipeline certification was at issue. These and other engagements are listed in my curriculum vitae, which is attached to this testimony as Exhibit PRC-1.

Q. Have your research or consulting engagements resulted in any publications?

A. Yes, these are listed in my c.v.

Q. Dr. Carpenter, what assignment were you given with respect to this proceeding?

A. I was asked by Florida Gas Transmission Corp. ("FGT") to review the evidence presented by the SunShine Pipeline Partners ("SunShine") in this proceeding, and to evaluate from my viewpoint as an economist whether that evidence is sufficient to support a public policy determination that the proposed SunShine pipeline is needed. In addition, I was asked to evaluate whether the equity ownership position of Florida Power Corporation ("FPC") in the SunShine project, and/or FPC's proposed regulatory treatment of this position, creates any special economic issues which should be taken into consideration by the Florida Public Service Commission ("FPSC" or "Commission") in its determination of the need for the project.

Q. How have you organized your testimony in this proceeding?

A. I have divided my testimony into three major sections. After briefly summarizing my conclusions and recommendations, I begin by describing the economic standards which the FPSC should employ to determine whether there is a need for the proposed SunShine pipeline. In the second section I evaluate whether the evidence presented by SunShine satisfies these standards. And finally, I consider the equity ownership position and proposed regulatory treatment of FPC's participation in the SunShine project. I explain how it affects the determination of need in this proceeding and I suggest how the Commission might appropriately respond.

SUMMARY OF TESTIMONY AND RECOMMENDATIONS

Q. Dr. Carpenter, could you please summarize briefly your conclusions and recommendations based on your evaluation of the issues in this proceeding?

A. Yes. I have reached three basic conclusions and recommendations:

1. There are two basic alternatives available to the FPSC for determining whether there is a need for the SunShine project. The traditional approach requires the performance of a cost-benefit and cost-effectiveness analysis of the project. The market-based alternative requires a showing of market support, i.e., that third-party shippers are willing to commit contractually to pay for the capacity proposed at its incremental cost, that the project sponsors are bearing all of the project's economic and financial risks, and that the competitive playing field is not tilted toward the project by explicit or implicit cross-subsidies from the state's gas and electric ratepayers.

2. SunShine's evidence in this proceeding fails to meet the economic standard required by either the traditional or market-based approach. It provides no quantitative or qualitative basis for allowing the FPSC to conclude that the project would pass a cost-benefit or a cost-effectiveness test. The evidence from signed precedent agreements shows that SunShine has failed to secure sufficient market interest in its project to support a market-based need determination at this time. It is also clear that the economic viability of the project is dependent on the successful subscription and utilization of its second and third stage expansions in 1998 and 1999. SunShine's showing of market commitment through signed precedent agreements for this latter time

period is insufficient to support a finding that the market has affirmatively committed to the project.

3. FPC's equity ownership in the project creates a conflict between its role as a project sponsor and its role as a customer of the project on behalf of its electric ratepayers. This conflict makes it very difficult for the FPSC to rely on a market-based standard for need determination in this case. FPC's equity ownership position creates incentives for project costs and risks to be allocated involuntarily to FPC's ratepayers, violating the requirement under a market-based approach that only project sponsors are to bear project risk and that cross-subsidies from ratepayers are to be avoided because they unfairly and inefficiently tilt the competitive playing field toward the subsidized project. FPC's proposed regulatory treatment for the pass-through of project costs and guaranteed rate of return is an example of just such a shift in project risks to ratepayers and cross-subsidy to the project.

ECONOMIC STANDARDS FOR NEED DETERMINATION

Q. What alternative regulatory approaches are available to the FPSC for determining whether the proposed SunShine pipeline project is needed?

A. There are essentially two alternatives available. One, that I will refer to as the "traditional approach," determines need on the basis of an explicit cost-benefit and cost-effectiveness analysis of the proposed project. The second alternative is a "market-based" approach, in which need is evaluated based on the willingness of third-party customers and shippers to commit contractually to the project and on the requirement that the project's economic and financial risks will be borne by the project sponsors and not by other customers or ratepayers.

The traditional approach requires that the regulatory commission make an affirmative finding that the project is likely to provide net benefits to consumers and that it is economically superior to other alternatives, including the alternative of delaying the project. To the extent that alternative projects are mutually exclusive, this approach may require the commission to choose between competing projects. The market-based approach relies on competition between alternative projects to determine which project(s) will be constructed, but the regulatory commission must ensure that the competition is effective and that there are no explicit or implicit cross-subsidies that would unfairly advantage any one competitor or distort customers' comparisons of the alternatives. Because the regulatory commission does not actually select between mutually exclusive projects, this approach is often referred to as the "let the market decide" policy of project certification.

Q. What is the specific nature of the economic analysis required to support a finding of need for a new natural gas pipeline under the traditional approach?

A. Two types of analysis are required: a cost-benefit and a cost-effectiveness analysis. Through a cost-benefit analysis the commission would determine whether the benefits to Florida gas consumers and electric ratepayers outweigh the costs of the project. The cost-effectiveness analysis would evaluate whether the proposed project was the alternative producing those benefits at the least cost.

Q. What types of benefits and costs would these analyses typically include?

A. The benefits of a new gas pipeline will typically involve economic as well as environmental considerations. Economic benefits which might be considered include the fulfilling of a new or unmet demand for gas or gas transportation services, reduced delivered gas prices, cost savings from the displacement of alternative fuels such as oil, and increased service reliability. Reduced gas prices may be achieved if the new pipeline provides access to lower-cost supply basins, cheaper upstream transportation arrangements, increased competition between gas supply and pipeline transportation suppliers, or increased utilization of fixed-cost facilities. Specific access and competitive improvements must be evaluated to determine if the benefits are quantifiable and significant relative to the status quo. Environmental benefits might include air quality improvements through the displacement of alternative fuels with higher levels of emissions.

The project costs to be considered would include capital and operating costs and the costs of any environmental mitigation necessary in the project's construction or operation. Because the timing of the incidence of costs and benefits can be important, the translation of the project's capital and operating costs into rates and the resulting time profile of such rates over the life of the project are important to the analysis. To reflect project timing in the analysis, the time profile of annual net benefits (net of costs) should be discounted at an appropriate rate of interest to yield the project net present value (NPV) of benefits. A project with a positive NPV would pass the cost-benefit analysis screen, although it still may not pass the cost-effectiveness test of need.

Q. What would a cost-effectiveness analysis entail?

A. Cost-effectiveness analysis considers whether there are alternatives to the proposed project, including the alternative of delaying the project's development, which would likely produce greater net benefits for Florida consumers at the same cost, or the same benefits at lower cost, on a present value basis. (Typically, only the latter is considered and is often dubbed "least cost" planning.)

Q. How could the alternative of project delay show potentially higher net benefits in a cost-effectiveness analysis?

A. When there is uncertainty as to whether future market conditions will support a project with irreversible initial capital investment requirements, the option to delay the project may have significant economic value. Much like a call option on a common stock can have value when the stock's price is volatile and its future price is uncertain, the option to wait to invest in a pipeline project for which demand is uncertain can have greater value than a policy of immediate certification and construction prior to the resolution of significant uncertainties. The value arises because the option to wait preserves the possibility of making the commitment later, while it reduces the chance of committing to the project at a time when its economics could turn sour. Simply stated, retaining the flexibility not to go forward when market conditions are uncertain, has value. This value is often important to recognize when one performs a cost-effectiveness analysis.

Q. Turning to the market-based approach you described, does this alternative permit the regulatory commission to take a "hands-off" attitude toward the proposed and competing projects?

A. In idealized conditions, yes, but these are almost never observed in a regulated environment. Because the approach relies on competition between alternative projects to ensure that the amount and timing of new capacity additions are "optimally" developed, the regulatory commission must be sure in the certification process that the competition will be unbiased and effective. In the situation of new pipeline projects, there are typically only a few potential sellers competing for a relatively small number of potential buyers. Individual transactions can be a large part of the total market, and the minimum feasible scale for entry into the market is quite large. Consequently, the market available to the new entrant must be correspondingly large. For these reasons, the structure of the "market" that is being relied on to determine project need is likely to be fairly "thin," i.e., less than adequately active to assure that a least-cost alternative is found.

Regulatory scrutiny is also required under a market-based need policy of any situation which might unfairly skew the results of the competition to one particular project. Of particular concern would be a cross-subsidy from ratepayers to a particular competitor due to the shifting of costs or risks away from the project and toward ratepayers. This can be a problem when there is a vertical affiliation between the regulated project sponsor and a regulated local utility company acting on behalf of its captive ratepayers.

Q. Given these considerations, what would be the appropriate elements of a showing of "need" under the market-based approach when such vertical affiliation occurs?

A. Under the market-based approach, need is demonstrated by (1) the willingness of new shippers or shippers with incremental loads to commit to the project at the project's incremental rates and (2) by the assurance that the project is not involuntarily subsidized by ratepayers. Consequently, the need showing should include the filing of signed long-term contracts or precedent agreements in which shippers have committed to paying demand or reservation charges for a significant fraction of the capacity of the pipeline and that cover a significant portion of the fixed investment costs of the pipeline over its lifetime. These long-term contracts serve as the "market's" expression of demand for the project's capacity.

If one of the project sponsors is a local public utility that is also a customer of the project, the sponsors should indicate the ways that they are bearing project risks in the case of underutilization or subscription default. Under these circumstances, a utility-sponsor should be required to insulate its ratepayers from future changes in rates due to the consequences of project underutilization or undersubscription.

Q. What if a utility-sponsor of a project wished to share the risks and rewards of the project with its ratepayers, and not place its shareholders totally at risk for its investment in the project?

A. If the utility-sponsor wished to make its ratepayers a partner in the project by virtue of this kind of risk allocation, then a showing of how the project explicitly provides net benefits to ratepayers would be appropriate. The market-based approach to need determination would have to be abandoned in favor of the traditional approach utilizing cost-benefit and cost-effectiveness analysis. The reason the market-based approach would no longer be appropriate is that the proposed risk and cost-sharing creates a disparity between the interests of the project's sponsors and the interests of the sponsor's own ratepayers, which will invalidate the use of a "market test" to select the most cost-effective and beneficial project.

Q. What are the consequences of each of these approaches for the FPSC's deliberations in this proceeding?

A. No matter which approach the Commission employs, it must take some care to ensure that the most cost-effective and beneficial pipeline projects are certificated and constructed. The market-based approach has its attractions, because in principle it leaves the decisions as to which projects to support to the entities that presumably have the best information. On the other hand, when there are cross-subsidy conditions or risk-shifting incentives present that might distort the market's judgement or tilt the competitive playing field, it will be necessary to cure the distortions prior to the certification of the project or to employ the more traditional economic analysis of need.

Q. Are you familiar with any other state utility commission's use of the market-based approach to gas pipeline need determination?

A. I am very familiar with the experience of the California Public Utility Commission (CPUC) in implementing a market-based policy for the certification of new gas pipeline capacity in its state.

Q. Could you briefly summarize California's experience with this policy?

A. Yes. In the late 1980's it became clear to the CPUC that there was a potential need for additional gas pipeline capacity into and within the State of California.

At that time southern California had been experiencing curtailments of gas supply, and the enhanced oil recovery industry (which uses natural gas-fired steam injection for oil production) was seeking firm gas supplies that the local utilities were unable to provide. Several inter- and intrastate pipeline construction and expansion proposals had been put forward to serve this and other demands. In deciding what its approach to pipeline certification and need determination would be, the CPUC settled on what it called the "let the market decide" policy. [I have attached to this testimony as Exhibit PRC-2 relevant excerpts from CPUC Decision No. D.90-02-016, which enunciated this policy, and rehearing Decision No. D.92-10-056, which applied this policy to the certification of an intrastate pipeline expansion proposed by Pacific Gas & Electric Co.] To receive CPUC certification under this policy (and support if the proposal was for an interstate pipeline), the proposed pipeline or expansion was required to make a showing of market interest in the project through signed contracts or precedent agreements.

By and large this policy was successful, as several of the proposed interstate pipeline expansions into southern California were rapidly constructed and put into operation. By the winter of 1992, expansions of the existing El Paso and Transwestern pipelines, and the entirely new Kern River and Mojave pipelines were brought on line, filling the apparent interstate capacity shortfall. (One of the competing proposals, the Coastal Corporation's WyCal pipeline project, failed to garner a sufficient market and was not constructed.)

The CPUC encountered significantly more difficulty with the market-based approach, however, for the proposed pipeline project sponsored jointly by Pacific Gas & Electric Company (PG&E) and its subsidiary Pacific Gas Transmission (PGT). The PGT/PG&E expansion project was a proposal to expand the existing PGT interstate pipeline from Canada to the northern California border, where it would be met by an expansion of PG&E's intrastate transmission line to southern California. The intrastate portion of the expansion required CPUC certification and a finding of need.

Q. What was the nature of the difficulty that the CPUC encountered after it certified the PG&E expansion project under its market-based policy?

A. Because PG&E was the sponsor of an inter- and intrastate pipeline project as well as a CPUC-regulated local distribution company serving residential "core" and commercial and industrial "non-core" customers, the CPUC was very mindful of the fact that its "let the market decide" policy could be compromised if PG&E were to be allowed to shift costs or risks involuntarily onto its ratepayers as a subsidy to its expansion project. Citing its market-based certification policy, it rejected repeated attempts by PG&E to (1) subscribe to the project on behalf of its core residential customers, and (2) roll-in the costs of the intrastate expansion into its existing LDC rates.

Q. Was the CPUC successful in establishing terms and conditions of certification that would prevent the compromise of its "let the market decide" policy?

A. No. Despite the rejection by the CPUC of these attempts at expansion project subsidy, by the winter of 1992 PG&E had commenced construction of its expansion project. The project is now nearly complete even though PG&E has signed long-term contracts covering only approximately 40 percent of the intrastate capacity of the project. Many observers of the California gas market believe that much of this additional capacity will ultimately be in excess of the state's needs, and could result in stranded capacity on the other interstate pipelines entering the state. At least part, and perhaps all, of the cost of this stranded capacity will ultimately be borne by the state's gas ratepayers, despite the stated intent of the CPUC that only PG&E's shareholders would bear the risk of project underutilization and undersubscription, because of the future inability to segregate the costs of the inefficiently expanded capacity. Once the excess capacity is built and operational, it will be very difficult to enforce an allocation of stranded costs that clearly places the risk of stranded investment on the utility-sponsor's shareholders.

Q. What went wrong in California, and what does this experience suggest for how the FPSC should approach gas pipeline need determination in this case?

A. The problem in California was not due to any intrinsic problem with its market-based certification policy. The problem was an error of implementation, in that the CPUC failed to recognize early enough the potential competitive problems that *utility-owned and sponsored* expansion projects present to a market-based policy. By the time these biases became understood, PG&E had already sunk hundreds of millions of dollars into the project. Though the premises of that investment were changed, the temptation to complete the project was apparently overwhelming. The lessons that I draw from this experience are twofold:

1) Despite its greater informational and analytical requirements, the traditional approach to need determination should be presumed to be more appropriate when proposed pipeline projects have local utility ownership and where the utility is also a customer of the project.

2) If the FPSC wishes to employ a market-based approach to need determination where utility-sponsorship is present, it must insist on a showing of unbiased, undistorted competition and not merely the sponsor's willingness to proceed. As in the PG&E/PGT case, such willingness is far from a valid indicator of cost-effectiveness. To implement this rule, the FPSC should require sufficient signed contracts demonstrating a long-term financial commitment to the project by the market, and it must insist that all current and prospective mechanisms to share costs and risks with captive ratepayers be removed as a condition of certification. (This could include some rather subtle subsidies, such as the utility providing a guarantee of project debt.) It must also be vigilant after certification to ensure that the local utility's market position is not used in the future to subsidize the project.

THE SUNSHINE PROJECT AND ITS SHOWING OF NEED

Q. Dr. Carpenter, what is your understanding of the physical and ownership structure of the proposed SunShine pipeline project?

A. The SunShine project is a proposed intrastate gas transmission line consisting of 362 miles of 30-inch mainline that would be constructed from a single interconnection point with the proposed SunShine Interstate Transmission Co. (SITCO) in Okaloosa County to a location in Sumter County in central Florida. In addition to the mainline, seven laterals would be constructed in central Florida for service in 1995 at a capacity of roughly 250 MMcf per day. In a second phase of the project three additional laterals would be added along with mainline compression to bring the design capacity to approximately 425 MMcf per day for service in 1998. It is also contemplated that additional compression will be added in 1999 to bring the system capacity to 550 MMcf per day.

The SunShine project is being proposed by a partnership consisting of ANR Southern, a subsidiary of the Coastal Corporation, and Power Energy Services Corp. (PESCORP), a subsidiary of Florida Power Corporation (FPC). FPC is a FPSC-regulated electric utility company. PESCORP currently holds one-third of the equity in SunShine, while the remaining two-thirds is held by ANR Southern.

Q. Whom has SunShine identified as customers of the proposed pipeline?

A. In its filed testimony in this proceeding, SunShine identified only FPC as a firm customer of the pipeline. (Burgin, pp.10-11) It indicated that FPC has signed on for firm transportation to its Anclote power plant and for its proposed Polk County units in 1998 and 1999. A review of the Precedent Agreement between FPC and ANR Southern reveals that FPC seeks a maximum daily quantity (MDQ) of 120,000 MMBtu per day for the Anclote Plant to commence on the in-service date of the SunShine facilities.

Additionally, FPC contemplates 45,000 MMBtu per day of MDQ for each of the two proposed Polk County units. The first unit's transportation demand would commence in August 1998 at the earliest and the second in August 1999 or later, assuming of course that the Polk units are approved by the FPSC for construction.

I understand that, subsequent to the filing of Sunshine's prepared testimony, ANR Southern has signed a precedent agreement with Peoples Gas System, Inc. ("Peoples") for service to Peoples gas distribution systems in Hernando, Pasco and Polk Counties. Peoples has agreed conditionally to a MDQ of 37,500 MMBtu per day on a year-round basis and an additional 12,500 MMBtu per day in the summer months commencing in 1995. It has also committed conditionally to an additional 25,000 MMBtu per day beginning in 1997 under this agreement. I also understand that SunShine has provided letters of intent with several additional potential shippers. The nature, timing and extent of these commitments is uncertain.

Thus, at this time it appears that SunShine has signed precedent agreements for firm MDQ's totalling 157,500 MMBtu per day year-round and 170,000 MMBtu per day in the summer months, or from 63 to 68 percent of its total proposed capacity in 1995. The comparable percentage commitment under current precedent agreements appears to be approximately 50 to 55 percent of its proposed capacity in 1998 and 1999. It should be noted that the vast majority of this commitment, at least 70 percent of the 1995 MDQ, is from FPC, an equity owner in the project.

Q. How firm are FPC's and Peoples' obligations under the Precedent Agreement with ANR Southern?

A. There are a series of conditions precedent which must be fulfilled by ANR

Southern prior to FPC or Peoples being obligated to pay reservation charges covering the loads that I identified above. Among these are 1) ANR Southern must have signed precedent agreements with shippers having an aggregate MDQ of 219,000 MMBtu per day by May 1, 1993 (in the case of FPC). They have at least 50,000 to 60,000 MMBtu per day of additional capacity to market this month in order to meet this condition. 2) ANR Southern must receive and accept all required regulatory authorizations in Florida by February 1, 1995. In addition, FPC will be relieved of its reservation charge obligations for the Polk unit loads if it is unable to receive all regulatory approval for these proposed power stations prior to the earlier of October 1, 1995 or 15 days prior to the scheduled vote of ANR Southern's Board of Directors to commence construction or accept a financing term sheet for the intrastate facilities.

Q. What is your understanding of the costs and proposed rates of the Sunshine project?

A. According to SunShine's filed testimony (Lucido, p.9), the capital cost of the initial phase of the project is estimated to be $437.5 million. The second and third phases are estimated to add capital costs of $127.9 and $53.5 million, respectively, for a total project capital cost of $618.9 million. SunShine has not provided any estimates of expected operations, maintenance or administrative costs for the project.

As to rates, SunShine apparently did not file any illustrative tariff rates for the project. The precedent agreement with FPC, however, describes the rates which were negotiated as a part of that transaction. It indicates that the initial rate for FT service on the intrastate facilities will be 52.5 cents per MMBtu. However, this is to be combined with the rate on the interstate

(SITCO) facilities according to a methodology which sets an Aggregate Rate Cap for service over both sets of SunShine facilities. This cap will initially be 71.8 cents per MMBtu, and the cap will escalate according to a formula that is partly tied to inflation (as represented by the GNP Price Deflator), is limited to a maximum of 4 percent per year, and to an ultimate ceiling on the nominal price of 84.0 cents per MMBtu during the first 20 years of the project.

Q. Did SunShine provide any evidence in its filing that these rates which it has negotiated in these precedent agreements are sufficient to cover the incremental costs of the project?

A. No. There was no evidence provided as to whether the commitments it has secured at these rates would be sufficient to make the project economically viable.

Q. Has any evidence been produced subsequent to SunShine's filing which sheds light on this subject?

A. Yes, but the balance sheet and income statement provided by SunShine relate only to the first seven years of the project. I have attached these as Exhibit PRC-3. As a consequence, the information provided by SunShine is insufficient to reach a conclusion about the consistency etween the projected operating revenues and the 52.5 cent rate. The first seven years projected by SunShine reveals that their projections of operating revenues assume a 100 percent load factor utilization at the 52.5 cent rate.

Q. How do these revenue numbers comport with the revenue requirements associated with the physical plant and its operating costs?

A. Over the seven-year time frame, these revenues per unit of throughput are considerably below the prices that would prevail under traditional cost-of-service revenue requirements. Indeed, the stated revenues do not appear to even generate positive cash flow in the first three years. Partly this is due to the desire to "levelize" rates, i.e., to defer revenue recovery to later years to avoid the "front-end load" that is associated with conventional ratemaking. But it appears that the levelization which SunShine is performing is based on the assumption that the full 1998 and 1999 expansions will be in place and fully utilized and they are apparently recognized in rates as early as 1995.

Q. Why is this significant to the need determination in this case?

A. It points out that the pipeline's capacity is far less subscribed than the capacity shares in the 1995 time frame would indicate. That is, the contribution towards cost recovery expected from the initial customers is less than the proportion of these claims on the available capacity.

Indeed, it is difficult to gain confidence from these pro forma statements that there is any strong possibility of recovering the construction costs of this pipeline, even well into the future. The deferral of capital recovery being proposed results in the accrual of a deferred asset with net value of $149.5 million by 1998. (These deferrals are booked as income on the other side of the balance sheet, increasing the equity value of the pipeline.) Evidently, this balance is to be amortized over subsequent years, presumably at an accelerating rate. At least initially (in 1999-2001), that amortization occurs so slowly that the deferred asset only falls in book value to $146.7 million by the end of 2001. If such slow rates of amortization are to be applied in subsequent years, the deferred asset will not be amortized for many years.

On the other hand, if such balances are to be amortized much more rapidly, then either the 52.5 cent rate or the capacity of the pipeline will have to increase further in years beyond 2001, in ways not yet explained by SunShine. Such a need for revenue increases would raise doubt as to whether the 52.5 cent rate for the intrastate transportation is meaningful in a market test, unless it is assumed that future, as yet unidentified customers will pay much more for the capacity than will initial customers. Alternatively, SunShine may be assuming that the pipeline's capacity will be increased even more in later years -- an assumption which is built into its current rates. If they exist, these plans have not yet been revealed.

Q. Dr. Carpenter, could you please summarize your understanding of SunShine's demonstration of need as contained in its filed testimony in this case?

A. Yes. SunShine's need showing is primarily contained in the testimony of Mr. E.J. Burgin and Mr. Judah Rose. (The other SunShine witnesses Lucido and Hrehor describe the engineering configuration of the project and the upstream pipeline and supply configurations available to its shippers.)

Mr. Burgin, SunShine's President and COO, describes the project and its current and anticipated customer base. While the volume commitments he describes are apparently insufficient to support the project and are still being negotiated, he suggests (p.13) that subsequent to its filing, and perhaps to its certification and construction, "SunShine will secure contracts with enough shippers for the threshold volumes that it needs to make the project economically feasible." He recommends (p.14-15) that the FPSC base its determination of need, in part, on the *potential* growth in the demand for gas in Florida. For evidence of this growth potential he turns to the testimony and analysis of Mr. Rose.

In addition to need as demonstrated by potential demand growth, Mr. Burgin argues that SunShine would provide a competitive alternative to FGT, and he asserts (p.15) that this competition has already resulted in bargaining concessions by FGT and SunShine. Finally, he claims that if the SunShine pipeline were not to be certificated, Florida would lose "new economic boosts and job creating opportunities." (p.18) Mr. Burgin does not provide or cite any specific economic evidence for these claims in his testimony.

Q. How does the market study performed by Mr. Rose demonstrate the need for SunShine's facility?

A. While market studies may have their place in a market-based need determination, Mr. Rose's analysis is never tied specifically to the economics, location, or proposed timing of the SunShine project. Instead, he conducts a macroeconomic analysis of the demand for electric generating capacity throughout the state of Florida with its resulting implications for firm gas pipeline capacity demand . He concludes that by the year 2010 there will be a demand for 5.0 Bcf per day of total pipeline capacity and by the year 2000 he estimates a demand for 3.8 Bcf per day of total pipeline capacity. Upon completion of FGT's Phase III expansion, existing pipeline capacity will be 1.5 Bcf per day, leading Mr. Rose to conclude "If the SunShine pipeline were built with a capacity of 0.8 Bcf/day, demand would still exceed supply."

Q. What is your understanding of Mr. Rose's assessment of gas pipeline capacity demand for the purposes of electricity production in 2000 and 2010?

A. Mr. Rose estimates the demand for firm gas capacity for electricity production to be the majority of total forecasted pipeline capacity demand, specifically, 3.4 Bcf/day in 2000 and 4.7 Bcf/day in 2010, as follows:

Load Segment	2000	2010
	Bcf/d	
Baseload	0.2	0.5
Intermediate	1.9	2.6
Seasonal Peak Load	1.3	1.6
Daily Peaking	0.0	0.0
Total	3.4	4.7

Q. How does Mr. Rose arrive at these estimates of firm gas capacity demand?

A. Mr. Rose goes through five steps to arrive at his figures. To begin, he estimates future load and peak electricity demand growth in Florida. Then, these growth forecasts are translated into demands for electric generating capacity, of which he distinguishes four types: baseload, intermediate, seasonal peak load, and daily peaking. Third, he performs a review of the economics of new generating plant technology to develop his opinion as to the proportion of new capacity that will be gas-fired. Specifically, he assumes 50% of the new baseload, 75% of the new intermediate, 50% of the new seasonal peak load and 0% of the new daily peaking electric capacity will be gas-fired and require firm gas pipeline transportation capacity. Mr. Rose also performs a review of the economics of existing oil-fired plants to estimate the gigawatts of existing capacity that will demand firm gas pipeline transportation. Quite conveniently, Mr. Rose concludes that 75% of existing intermediate capacity and 50% of existing seasonal peak load capacity -- i.e., the same proportions as new capacity in those categories -- will demand such transportation. Finally, he then translates the gigawatts of electric capacity demand into bcf/day estimates of gas pipeline capacity demand by imposing utilization and heat rate assumptions on the four different categories of plants.

The one thing Mr. Rose's testimony never really does is to look at the actual generating capacity expansion plans of Florida's electric utilities. His workpapers indicate that he had the specific project information available to him, however, his only use for it was in estimating the proportion of new plants that would be gas-fired. Mr. Rose's analysis is at best a poor substitute for the actual plans developed by Florida's electric utilities. By ignoring these plans and instead analyzing the problem in an aggregate manner, Mr. Rose loses a great deal of valuable information and grossly overestimates the demand for SunShine.

Q. How do you reach this conclusion?

A. Exhibit PRC-4 lists the gas-fired capacity changes for Florida reported in the North American Electric Reliability Council's (NERC's) *Electricity Supply & Demand 1992-2001*. This list reflects utility and non-utility gas-fired generation additions and utility plant retirements as planned for and reported by Florida's electric utilities. There are at least three things to note about this list.

First, the majority of the capacity additions between 1992 and 1997 are to be served by existing Florida Gas Transmission (FGT) capacity or by FGT's Phase III expansion. Thus, demand over the next five years by electric generating stations for new pipeline capacity has largely been satisfied.

Second, plans for 1998 through 2001 are of a more tentative nature -- many are at too early a stage to make a firm commitment for pipeline capacity. For example, note that there are no new non-utility generation additions currently forecasted for that time period (a non-utility generation project is designated by an "N" in the <u>Ownership</u> column.) This is not to say that there will not be any such projects, only that the utilities are currently unable to forecast specific projects.

In addition, many of the utility projects are essentially "placeholders."

The utility knows it will need electric capacity if its forecasts turn out to be correct and so it specifies capacity of a type (i.e., technology) that appears to be economic but the utility itself has not yet authorized the project. Thus, under the column Status, most of the projects have a "P" which means planned, but not yet utility-authorized. Their tentative nature is also illustrated by the project names, with some going only by the generic labels "Peaker" or "Unknown."

Third, some of these later projects are expected to be at existing sites. Consider Florida Power & Light's Martin Units 5 and 6, slated for service in 2000 and 2001. Its Ten Year Power Plant Site Plan, 1992-2001 states (p.) that "The Martin site ultimately will be capable of approximately 1,600 MW of combined cycle generating capacity, comprised of four units, fueled primarily by natural gas or coal-derived gas produced at the Project site. The project will be undertaken in several phases. In Phase I, two combined cycles (Units Nos. 3 and 4) will be firing natural gas ... In Phase II, Combined Cycle Units 5 and 6 will also be natural gas fired." While SunShine could conceivably serve this demand, given that FGT is serving Units 3 and 4, it seems likely that it would be more economic for FGT to serve units 5 and 6.

Q. What are the implications of this for SunShine's showing of need?

A. It is not surprising that SunShine's results in committing power plant load to its project have been somewhat less successful than Mr. Rose's optimistic projections would suggest. FGT's Phase III expansion is serving most of the electric capacity demand in the time horizon relevant to the immediate application and SunShine's timing is a bit premature to be serving the out years of the forecast. Electric utilities are perhaps not yet willing to sign precedent agreements for firm pipeline capacity because these projects are only on the drawing board and have not officially received authorization from the utilities themselves.

This points up the irrelevance of Mr. Rose's year 2000 and 2010 analysis to this proceeding. Looking out to the year 2000 and beyond as a means of justifying the need for a gas pipeline *that would commence operations in 1995* is not informative. Economics would say that given the uncertainty in long-range demand forecasts, there is value in preserving the option not to construct the capacity addition by waiting until the demand truly materializes. Furthermore, given the lack of economic viability of the project at its negotiated rates in the 1995-1999 time frame as shown in the pro forma financial statements, both the demand for and cost of the initial stages of the project suggest that SunShine's application is premature.

NEED FOR SUNSHINE UNDER THE TRADITIONAL APPROACH

Q. Dr. Carpenter, do you believe that SunShine's filed evidence in this proceeding is sufficient to meet the economic standard required by a traditional need analysis that you outlined above?

A. No, it is clearly insufficient in at least three ways. First, none of the evidence presented provides sufficient information to perform a cost-benefit analysis. On the benefits side, Mr. Burgin asserts that certain competitive and macroeconomic benefits may accrue to Florida, but he provides no basis on which any of these benefits could be quantified or their significance for SunShine ascertained. On the cost side, the pro forma financial statements discussed above suggest that the project's own economics are not supported by its negotiated rates -- at least in the first four years of operation.

Second, there is no evidence that the project is superior to alternative projects, or even to the alternative of delaying the start of the project until the demand for its capacity is well-established. As discussed, Mr. Rose's analysis provides no insights, because even if the demand for gas-fired power plants that he estimates for the year 2000 and 2010 were correct, his analysis provides no support for the 1995, 1998 and 1999 in-service dates for the various phases of the project. Even if Mr. Rose's analysis were to support the proposed timing of the project, his analysis cannot contribute to a cost-effectiveness test because his growth forecasts are disconnected from the planned location and economics of the SunShine project. In other words, Mr. Rose's analysis would equally support any proposed gas pipeline into Florida, including an expansion of FGT. It might even be used in support of electric DSM programs that could reduce the long-range forecasted need substantially.

NEED FOR SUNSHINE UNDER A MARKET-BASED APPROACH

Q. Does SunShine's evidence provide sufficient support for a finding of need under the market-based approach that you outlined above?

A. Not in my opinion. As I mentioned, because the market-based approach relies on the willingness of third-party shippers to commit financially to the project, evidence of such a commitment should be a primary element of a market-based need showing. In this case, SunShine has signed precedent agreements that cover less than 70 percent of its initial project capacity and only 50-55 percent of its ultimate proposed capacity. And even these commitments are tenuous. For example, the agreement with FPC is conditioned on SunShine signing precedent agreements covering 50-60 MMcf per day of additional 1995 load in the next few weeks. At the very least, the precedent agreements indicate that the filing is premature under a market-based framework.

More importantly, however, the negotiated rate of 52.5 cents, described above, is not apparently sufficient to allow SunShine to recover its investment in the initial phase of the project, even if the project was fully utilized between 1995 and 1998. In other words, because the economic viability of these precedent agreements for the 1995 to 1998 time period relies on the successful further expansion, contracting and utilization of the SunShine project in the post-1998 time frame, these precedent agreements by themselves are not a demonstration that the initial phase of the project has passed a market test -- even if SunShine had 100 percent of the initial 250 MMcf per day committed to shippers.

Q. SunShine has also produced various "letters of intent." Are these letters evidence of market commitment to the project sufficient to satisfy a market-based need standard?

A. No they are not. These letters evidence no financial commitment by shippers whatsoever. In fact, the letter agreement between ANR Southern and Cypress Energy Partners, which I have attached as Exhibit PRC-5, actually indicates that the parties have *failed* to reach a precedent agreement, and that they are only agreeing to continue to negotiate in hopes of reaching a real agreement by May 8, 1993. Even in that circumstance, the potential Cypress volumes are only relevant to a post-1998 time frame and even that is for a highly speculative venture at best.

Q. If SunShine had been able to demonstrate a market commitment through signed precedent agreements, would just the mere existence of the agreements be sufficient to satisfy a market-based need standard?

A. No. Because the degree of financial commitment obtained in precedent agreements can vary widely, it is important that the FPSC look carefully at the specific language of the agreements, the terms (including the negotiated rates) of service, and the contingencies which allow the parties to unilaterally withdraw from the agreements. For example, an agreement in which the shipper agrees to only pay volumetric rates for the volumes actually taken, or has the unilateral right to reduce its contractual commitments once pipeline construction commences should be given less weight as an expression of market need for the capacity.

Q. What about Mr. Burgin's chicken/egg argument that regulatory filings often need to be made in order to convince shippers to commit to the project?

A. While I do not doubt that a project's credibility can be enhanced with the filing of formal applications, the more important factors underlying potential shippers' decisions to commit are likely to involve the economics of the project and the reputation of its sponsors relative to the alternatives -- which is exactly what one wants a "market test" to ferret out. Certainly a regulatory determination of need should not be granted simply to enhance the credibility of a single competing project in the eyes of potential shippers and customers. That *per se* contradicts the market test philosophy.

Q. Mr. Burgin also argued that the Commission should provide SunShine a certificate because it provides Florida with a competitive pipeline alternative to FGT. Do you agree?

A. I do not agree that this should be the sole or even the most important element of the Commission's need determination in this case. As Mr. Burgin himself points out in his testimony, the mere prospect of potential entry by SunShine has provided competition to the FGT alternative. But I would also point out that conditions in the gas pipeline industry have changed significantly in the last few years, and indeed months, such that the presence of a single interstate pipeline supplier in a given state or region no longer has the competitive implications it once had.

Under the capacity releasing features of FERC Order 636, and with gas pipelines providing principally transportation services in the new regime, pipelines no longer have control over access to capacity on their systems. In fact, under capacity releasing, pipeline capacity will be available on both a short or long term basis to shippers willing to pay for it. Mr. Hrehor, in his testimony for SunShine in the proceeding (pp.6-8), speaks quite favorably of the prospect of a secondary market in capacity on pipelines upstream of SunShine under Order 636. Indeed, he argues that this mechanism is what will assure SunShine shippers of firm capacity on upstream pipelines. But if shippers could obtain this capacity competitively upstream of SunShine under Order 636, there is no reason why they could not obtain capacity competitively on FGT under Order 636. In effect, Order 636 has created competition among many holders of capacity rights on existing pipelines that may not have existed prior to the Order. This substantially lessens the benefits associated with SunShine's entering the Florida market.

THE EFFECT OF FPC EQUITY PARTICIPATION IN THE SUNSHINE PROJECT

Q. You mentioned above that an important element of regulatory need determination under the market-based approach is a requirement that project sponsors' shareholders bear the economic and financial risks of the project. Has SunShine demonstrated that it has met this requirement?

A. No, it has not. If SunShine were being proposed solely by a stand-alone third party that did not have utility interests and ratepayers in the state of Florida then this would not be a serious concern. It could be presumed that if the project failed to achieve sufficient subscription or utilization levels, electric and gas ratepayers would be protected from sharing in these costs or risks. Shippers who initially committed to the project would be protected by the terms of the long-term contracts that they signed. They would not bear project risks unless they voluntarily agreed to do so, perhaps in return for other contract concessions, when they made their initial commitment to the project.

FPC's involvement in SunShine as both an equity owner, and as its principal shipper on behalf of FPC's electric ratepayers, creates a serious conflict of interest that could distort any market-based determination of need.

Q. Does the apparent ability of FPC to back out of the project prior to the commencement of construction affect your conclusion as to the effect of FPC's ownership on the determination of need?

A. No, it does not. The problem arises because equity ownership by FPC creates an incentive to shift project costs and risks to its ratepayers that may cause the project to be constructed when it would otherwise fail an unbiased market test. Thus the damage occurs after the decision to construct is made and after FPC has sunk its equity dollars. At that stage it would be surprising if FPC could back out of the project without, at a minimum, losing its equity investment.

Q. Dr. Carpenter, does the mechanism under which FPC proposes to treat the costs associated with its commitment to ship gas on SunShine exemplify the incentive of FPC as an equity owner to shift project costs and risks to its ratepayers?

A. Yes, it does. I understand that FPC is seeking regulatory approval for an automatic passthrough mechanism in its electric rates for the costs of its shipments over SunShine.

Q. How does it propose to treat its equity participation in the context of this passthrough mechanism?

A. FPC is proposing that it be guaranteed a rate of return at the upper end of its allowed rate for its electric business. This return would be part of the cost automatically passed-through to electric ratepayers, and it would be guaranteed by virtue of an annual "true-up" procedure. That is, if Sunshine earned less than this allowed rate, the difference would be collected from ratepayers in a subsequent surcharge. If it earned more, then the difference would be rebated to FPC's electric ratepayers. I have attached as Exhibit PRC-6 the February 23, 1993 document which FPC provided to the FPSC Staff outlining this proposed arrangement.

Q. What is wrong with this mechanism and how does it affect the determination of need in this proceeding?

A. The mechanism would have the effect of shifting all of FPC's ownership risk in the project to its captive ratepayers. If the project performs worse than expected, ratepayers bear the consequences, and if it does better than expected, ratepayers benefit. This behavior fits the classic financial economic definition of risk as the bearing of variance in project cash flows. Moreover, FPC's ratepayers don't even receive the expected return for bearing this equity risk -- FPC's shareholders do, since they are the party receiving the higher end of the range of allowed returns for bearing essentially no cash flow risk!

This shifting of costs and risks constitutes a cross-subsidy to the SunShine project which is not available to competing projects in the marketplace. Consequently, if the Commission chooses to rely on a market-based need determination in this proceeding, this pass-through mechanism may affect the competition such that the market-test may no longer be reliable. Indeed, the fact that FPC seeks such protections as a part of its involvement in SunShine should be an indication to the Commission that SunShine would fail the market test in the absence of the cross-subsidy from ratepayers.

Q. How would you propose that the Commission respond in this proceeding to the problems presented by FPC's equity participation in the SunShine project?

A. Certainly one alternative would be to rely on the more traditional approach to need determination requiring an explicit cost-benefit and cost-effectiveness analysis. In addition to such a showing for SunShine itself relative to the alternatives, this would require FPC to demonstrate that the benefits of its equity ownership position in SunShine outweigh the costs imposed on ratepayers by virtue of the project risks they are being asked to bear.

If the Commission decides to pursue the market-based approach to need determination it must effectively sever FPC's ownership role in the project from its shipper role on behalf of its ratepayers. This would require that FPC's passthrough proposal be denied, and that FPC's equity in SunShine be effectively segregated from the electric utility side of its business. The risks that FPC may bear as an equity participant in SunShine also must not be allowed to affect its utility allowed rate of return, and thus procedures would likely be required to isolate and prevent FPC's utility cost of capital determination from being affected by SunShine's risks.

Q. Does this complete your prepared testimony?

A. Yes, it does.

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Exhibit ___ (PRC-1)
Docket No. 920807-GP

April 1993

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Education

Ph.D.	Massachusetts Institute of Technology, Cambridge, MA: Applied Economics, 1984.
M.S.	Massachusetts Institute of Technology, Cambridge, MA: Management, 1976.
B.A.	Stanford University, Palo Alto, CA: Economics, 1976, (with Honors).

Employment

Incentives Research, Inc., Boston, MA:
(1983 - Present): President and co-founder of firm providing economic and financial counsel in the fields of oil and gas regulatory policy, economics, antitrust, and technology policy.

MIT Center for Energy Policy Research, Cambridge, MA:
(1981 - 1984): Research staff and post-doctoral fellow.

Putnam, Hayes & Bartlett, Inc., Cambridge, MA:
(1980): Associate.

NASA/Caltech Jet Propulsion Laboratory, Pasadena, CA:
(1978 - 1980): Economist and Project Task Manager.

MIT Energy Laboratory, Cambridge, MA:
(1976 - 1978): Research staff.

Professional Affiliations

International Association of Energy Economists
American Bar Association (Antitrust Section)
American Economic Association

Fields of Specialization

Industrial Organization
Antitrust
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Energy Economics
Corporate Finance and Strategy

Academic Honors and Fellowships

Stewart Fellowship, 1983
MIT Fellowships, 1981, 1982, 1983
Brooks Master's Thesis Prize (Runner-up), MIT, 1978

Publications

"Creating a Secondary Market in Natural Gas Pipeline Capacity Rights Under FERC Order No. 636," draft December 1992, Incentives Research Inc., (with Frank C. Graves).

"Review of the Component Design Report, Natural Gas Annual Flow Module, National Energy Modeling System," August 1992, prepared for the U.S. Department of Energy, Energy Information Administration.

"Unbundling, Pricing, and Comparability of Service on Natural Gas Pipeline Networks," November 1991, prepared for the Interstate Natural Gas Association of America (with Frank C. Graves).

"Review of the Gas Analysis Modeling System (GAMS): Final Report of Findings and Recommendations," August 1991, prepared for the U.S. Dept. of Energy, Energy Information Administration.

"Estimating the Cost of Switching Rights on Natural Gas Pipelines", The Energy Journal, October 1989 (with F. C. Graves and J. A. Read).

"Demand-Charge GICs Differ from Deficiency-Charge GICs", Natural Gas, Vol. 6 No. 1, August 1989 (with F.C. Graves).

"What Price Unbundling?", Natural Gas, Vol. 5 No. 10, May 1989 (with F.C. Graves).

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"Field Price Decontrol of Natural Gas, Pipeline Risk and Regulatory Policy", in Government and Energy Policy, Richard L. Itteilag, ed., Washington D.C., June 1983.

"Risk Allocation and Institutional Arrangements in Natural Gas", invited paper presented to the American Economic Association Meetings, San Francisco, December 1983 (with Arthur W. Wright).

"Vertical Market Arrangements, Risk-shifting and Natural Gas Pipeline Regulation", Sloan School of Management Working Paper No. 1369-82, September 1982 (revised April 1983).

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Book Review of An Economic Analysis of World Energy Problems, by Richard L. Gordon, Sloan Management Review, Spring 1982.

"Perspectives on the Government Role in New Technology Development and Diffusion", MIT Energy Lab Report No. 81-041, November 1981 (with Drew Bottaro).

International Plan for Photovoltaic Power Systems, Solar Energy Research Institute with the Jet Propulsion Laboratory Prepared for the U.S. Department of Energy, August 1979 (co-author).

Federal Policies for the Widespread Use of Photovoltaic Power Systems, Jet Propulsion Laboratory Report to the U.S. Congress DOE/CS-0114, March 24, 1980 (contributor).

"An Economic Analysis of Residential, Grid-connected Solar Photovoltaic Power Systems", MIT Energy Laboratory Technical Report No. 78-007, May 1978 (with Gerald A. Taylor).

Speeches/Presentations

"GIC's and the Pricing of Gas Supply Reliability," California Energy Commission Conference on Emerging Competition in California Gas Markets, San Diego, Ca. November 9, 1990.

"The New Effects of Regulation on Natural Gas Field Markets: Spot Markets, Contracting and Reliability," American Economic Association Annual Meeting, New York City, December 29, 1988.

"Appropriate Regulation in the Local Marketplace", Interregional Natural Gas Symposium, Center for Public Policy, University of Houston, November 30, 1988.

"Market Forces, Antitrust, and the Future Regulation of the Gas Industry", Symposium on the Future of Natural Gas Regulation, American Bar Association, Washington D.C., April 21, 1988.

"Valuation of Standby Tariffs for Natural Gas Pipelines", Workshop on New Methods for Project and Contract Evaluation, MIT Center for Energy Policy Research, Cambridge, March 3, 1988.

"Long-term Structure of the Natural Gas Industry", National Association of Regulatory Utility Commissioners Meeting, Washington D.C., March 1, 1988.

"How the U.S. Gas Market Works - or Doesn't Work", Ontario Ministry of Energy Symposium on Understanding the United States Natural Gas Market, Toronto, March 18, 1986.

"The New U.S. Natural Gas Policy: Implications for the Pipeline Industry", Conference on Mergers and Acquisitions in the Gas Pipeline Industry, Executive Enterprises, Houston, February 26-27, 1986.

Various lectures and seminars on U.S. natural gas industry and regulation for graduate energy economics courses at Massachusetts Institute of Technology, 1984-85.

Panelist in University of Colorado Law School workshop on state regulation of natural gas production, June 1985. (Transcript published in University of Colorado Law Review.)

"Oil Pipeline Rates after the Williams 154 Decision", Executive Enterprises, Conference on Oil Pipeline Ratemaking, Houston, June 19-20, 1984.

"Issues in the Regulation of Natural Gas Pipelines", California Public Utilities Commission Hearings on Natural Gas, San Francisco, May 21, 1984.

"Financial Aspects of Gas Pipeline Regulation", Pittsburgh Conference on Modeling and Simulation, Pittsburgh, April 19-20, 1984.

"Natural Gas Pipelines After Field Price Decontrol", Presentations before Conferences of the International Association of Energy Economists, Washington D.C., June 1983, and Denver, November 1982.

"Spot Markets for Natural Gas", MIT Center for Energy Policy Research Semi-annual Associates Conference, March 1983.

"Pricing Solar Energy Using a System of Planning and Assessment Models", Presentation to the XXIV International Conference, The Institute of Management Science, Honolulu, June 20, 1979.

Testimonial Experience

Antitrust/Federal Court:

Deposition and Trial Testimony in State of Illinois v. Panhandle Eastern Pipeline Co. (Fed. Ct. for C.D. Ill) 1984-87.

Deposition Testimony in Sinclair Oil Co. v. Northwest Pipeline Co. (Fed. Ct. for Wyoming) 1987

Trial Testimony in City of Chanute, et al. v. Williams Natural Gas (Fed Ct. for Kansas) 1988

Deposition Testimony in Martin Exploration Management Co., et al. v. Panhandle Eastern Pipeline Co. (Fed. Ct. for Colorado) 1988 and 1992

Deposition and Testimony by Affidavit in Merrion Oil and Gas Co., et al., v. Northwest Pipeline Corp. (Fed. Ct. for New Mexico) 1989

Testimony by Affidavit in James River Corp. v. Northwest Pipeline Corp. (Fed. Ct. for Oregon) 1989

Deposition Testimony in Fina Oil & Gas v. Northwest Pipeline Corp. and Williams Gas Supply (New Mexico) 1992

Economic/Regulatory Testimony:

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Alberta Energy Resources Conservation Board, on Applications of NOVA Corporation of Canada to Construct Facilities, January 1993.

Before the California Public Utilities Commission, on the Application of Pacific Gas & Electric Co. to guarantee certain financing arrangements of Pacific Gas Transmission Co. not to exceed $751 million.

Unocal California Pipeline Co., FERC Docket No. IS92-18-000, August 1992.

Before the California Public Utilities Commission, in the Rulemaking into natural gas procurement and system reliability issues, R.88-08-018, June 1992.

Alberta Energy Resources Conservation Board, Altamont & PGT Pipeline Projects, Proceeding 911586, March 1992.

Before the California Public Utilities Commission, on the Application of Southern California Gas Company for approval of capital investment in facilities to permit interconnection with the Kern River/Mojave pipeline, A.90 11-035, May 1992.

Northern Natural Gas, FERC Docket No. RP92-1-000, October 1991.

Florida Gas Transmission, FERC Docket No. RP91-187-000 and CP91-2448-000, July 1991.

Tarpon Transmission, FERC Docket No. RP84-82-004, January 1991.

Before the California Public Utilities Commission, on the Application of Pacific Gas & Electric Co. to Expand its Natural Gas Pipeline System, A.89-04-033, May 1990 and October 1991.

CNG Transmission, FERC Docket No. RP88-211, March 1990.

Panhandle Eastern Pipeline, FERC Docket No. RP88-262, March 1990.

Mississippi River Transmission, FERC Docket No. RP89-248, October 1989, September 1990.

Tennessee Gas Pipeline, FERC Docket No. CP89-470, June 1989.

Empire State Pipeline, Case No. 88-T-132 before the New York Public Service Commission, May 1989.

Before the U.S. Congress, House of Representatives, Committee on Energy and Commerce, Subcommittee on Energy and Power, Hearings on "Bypass" Legislation, May 1988.

Tennessee Gas Pipeline, FERC Docket No. RP86-119, 1986-87

Mojave Pipeline Co., FERC Docket No. CP85-437, 1987-88

Consolidated Gas Transmission Corp., FERC Docket No. RP88-10, 1988

Panhandle Eastern, FERC Docket No. RP85-194, 1985

On behalf of the Natural Gas Supply Association in FERC Rulemaking Docket No. RM85-1, 1985-86

On behalf of Panhandle Eastern Pipeline Co. in FERC Rulemaking Docket No. RM85-1, 1985

Re Interstate Natural Gas Pipeline Supply and Capacity

Decision 90-02-016
I. 88-12-027

California Public Utilities Commission
February 7, 1990

ORDER approving conditions for the construction of new natural gas pipelines from out-of-state.

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1. GAS, § 1 — Pipeline capacity — New construction — State review of need — Competition as a factor.

[CAL.] The commission found that the construction of new interstate natural gas pipeline capacity was a necessary part of the solution to the state's demonstrated need for additional capacity, and that proposals to increase capacity by more efficient use of existing facilities — e.g., capacity reassignment, capacity brokering, and better interutility cooperation — were insufficient by themselves to solve the problem; in addition, it was found that the construction of new facilities would promote gas-on-gas competition to the benefit of all consumers outweighing any added costs to core customers resulting from diversions from the existing system.
p. 512.

2. MONOPOLY AND COMPETITION, § 58 — Gas plants and systems — Effect of competition on local supply costs — Pipeline capacity as a factor.

[CAL.] Increased competition in supply and transportation markets would result from the construction of new interstate natural gas pipeline facilities as demonstrated by the ability of certain local utilities with excess pipeline capacity and access to lower cost markets to maintain lower overall supply costs.
p. 512.

3. GAS, § 1 — Pipeline capacity — Need for new construction — State commission policies.

[CAL.] A "market-responsive" long-term policy on additional interstate natural gas pipeline capacity available to local gas companies was adopted by the commission reflecting a recognition of current capacity shortages and a range of need for capacity from 900 MMcf/d for the near term to 2.1 Bcf/d over the subsequent 15 year period.
p. 514.

4. GAS, § 1 — Pipeline capacity — Need for new construction — Effect of state commission rate policies — Unbundled rate structure.

[CAL.] The need for interstate natural pipeline capacity available to local gas companies was increased as a result of the unbundling of natural gas service by the commission as part of a restructuring of state regulation; bundled service minimized the need for pipeline capacity because the local distributor pooled all downstream consumers while the pipeline company pooled all upstream producers, as opposed to the "lumpy" demand pattern on the system under an unbundled rate structure with large numbers of individual decision makers.
p. 514.

5. GAS, § 1 — Pipeline capacity — Need for new construction — State review — Factors — Costs associated with unreliable transportation service.

[CAL.] In adopting a policy to encourage the development of new interstate natural gas pipeline capacity available to local gas companies, the commission found that the cost of additional capacity must be compared with the hidden costs of unreliable transportation service, such as expensive standby commodity service from local distributors, higher system costs due to balancing requirements, switching to alternate fuels, and the inability to profit from post-deregulation gas price competition.
p. 515.

6. GAS, § 1 — Pipeline capacity — Need for new construction — State review — Factors — Environmental concerns — Air quality.

[CAL.] Environmental goals, particularly the need to improve air quality, were cited by

VIII. *The New Pipeline Policy of the Commission*

A. *The Pipeline Market*

Today's decision is unique in its frank acknowledgment of uncertainty inherent in all efforts to forecast demand, and in its careful harnessing of competitive forces to attain statutory goals and requirements. As traditional utility services become more and more competitive,[17] responsible regulation can and should enlist competitive forces to the extent that their operation will result in furthering what have always been the goals of public utility regulation: reliable service and reasonable rates.

We know that California needs additional gas pipeline capacity into the state. We do not know precisely how much capacity is needed. We can only say that the need falls somewhere in between the relatively modest amount required in the near-term to ensure reliable service to the core and to connect California to additional producing areas, and the potentially vast amount that would be required in the long-term if the demands of the noncore market and of attaining air quality objectives turn out to be as great as some have projected.

This uncertainty creates great risks. If we forecast a single volume for demand, and require our LDCs and electric utilities to plan for and commit to precisely that amount of additional capacity, we would embark on a course that may result in the wrong timing or the wrong amount of additional capacity. The excess costs of such misguided regulation would be borne primarily by the LDCs' captive customers, namely, core ratepayers. On the other hand, we could forecast a *range* of demand, and allow the timing and the amount of additional pipeline capacity to be determined primarily by the willingness of those purchasing or investing in capacity to bear the risk of that investment. In other words, those who have the most to gain would rightly bear the risks due to uncertainty.

The record of this proceeding demonstrates that there is both a widespread perception of growing gas demand in California and a willingness to compete to serve that demand. New producers and producing areas seek ready access to the California market. Pipeline companies seek new routes and/or spurs to new areas that can complement their existing facilities. Both producers and pipelines recognize that the California market is large and growing, and they have shown that they are ready to compete for market share. Furthermore, our unbundling of gas commodity and transportation service has alerted the California market to the need to plan for its transport needs. Sophisticated gas purchasers in California can now bargain expertly and exercise leverage in exchange for their subscription to firm capacity rights. This competitive process, in a perfect market, could reasonably be expected to result in an optimal amount of additional pipeline capacity into California.

[9] However, despite assertions to the contrary, there is no true "free" market for pipeline transmission capacity: All pipelines seek regulatory guarantees for their cost recovery, and they could not be financed without this regulatory protection. In one form or another, California consumers or shippers of natural gas from other states or Canada will be required to pay for these projects. The market for pipeline capacity, like most markets in the real world, has imperfections. These arise partly from the impact of regulation, such as the desire of pipelines for cost recovery guarantees or the prior decisions of this Commission opposing bypass pipelines. We sense that California LDCs are reluctant to make firm commitments for additional capacity without affirmative guidance from this Commission. Such reluctance, in the current circumstances, may be causing *underinvestment* in additional capacity. Elsewhere in today's decision, we provide guidance to the LDCs for committing to additional pipeline capacity on behalf of the core.

Another kind of market imperfection, one that has greatly concerned us, is the possibility that pipeline costs, by one means or another, may be shifted away from the cost-causers. Specifically, to the extent that additional capacity would serve noncore customers it should be paid for by them, not by core ratepayers. If costs were shifted away from the cost-causers, the result would be unfair and would likely lead to *overinvestment* in additional capacity.

[10] Traditionally, the solution to market imperfections has been to oppose competitive forces through strict regulation, at least in the public utility sector. Increasingly, this traditional solution has come into question. Critics have cited cost overruns and overcapacity in electrical generation as examples of how regulation does not necessarily minimize either costs or risks. Competition has been successfully introduced in electrical generation and other services formerly reserved to regulated monopolies. The question at hand is whether our duty to regulate in the public interest necessarily precludes us

from utilizing competitive forces in determining the amount and timing of additional pipeline capacity into California. Pipelines are natural monopolies even where several pipelines serve a given market. It is the CPUC's primary function to regulate monopoly utility services such as gas transmission, even as we loosen regulation over more competitive areas, like the buying and selling of the gas commodity itself.

However, we believe that the time is right for us to guide and work with, rather than command and restrain, the competitive forces engaged in the pipeline market. First, regarding our LDCs, we have developed an appropriate record in this proceeding for modifying our prior position on additional pipeline capacity and for providing the guidance that the LDCs' management needs. We fully expect the LDCs to exercise their own judgment to evaluate the pipeline projects and the timing and amount of additional capacity that best suit each utility's situation. Second, the conditions we have announced for our willingness to support any given interstate pipeline project into California are crafted in large part to ensure appropriate assignment of costs to cost-causers. These conditions send a key message to potential users and sponsors of additional pipeline capacity. These conditions also protect the interests of core ratepayers. Having established these conditions, this Commission has fulfilled its regulatory obligations and enabled competitive forces to work in ways ensuring that private risk-taking will serve the public good.

B. *The Commission's Criteria for New Pipelines and the Proposed Settlements*

[11] To provide the necessary guidance to the utilities to facilitate new pipeline capacity, we next address the criteria set out in our original decision in this matter, I.88-12-027. After careful consideration of the proposed settlements, and the comments on the proposed decision, we have concluded that with slight modification, our original criteria for new pipeline capacity remain valid and are the proper basis for the Commission's support of any new capacity. We will support new pipeline expansion projects which fully comport with these criteria. We will address each criterion in order, precisely as they were originally stated in I.88-12-027.

1. *Economic Justification for New Pipeline Capacity*

> The amount of new pipeline capacity proposed must be economically justifiable as a means to provide more reliable access to long-term gas supplies, to enhance transportation reliability, to achieve gas cost reductions through gas-on-gas competition or to serve incremental demand, including that of EOR customers.
>
> New capacity additions must be economically justified on the basis of total delivered cost of gas from each of the producing areas designated below, including a showing of competitive transmission costs.

[12] These two criteria remain unchanged. There must be a valid need for the proposed capacity addition and a showing that the delivered cost of gas will be competitive. The need for new capacity has been demonstrated to our satisfaction in this proceeding, as discussed herein. The competitiveness of the delivered cost of gas on each pipeline will be demonstrated primarily through the willingness of customers to execute contracts for firm capacity on the new pipeline. Utility contracts for new capacity will remain subject to Commission approval in subsequent proceedings.

2. *Supply Diversity*

> Any new proposal for pipeline capacity should result in an interstate pipeline network which provides California with reliability of access to all the major producing areas within immediate reach of the state. (E.g., Canada, Overthrust, and Southwest, including New Mexico coal seam gas reserves.)

[13] We continue to support increased supply diversity for the state. It is of particular importance to access Wyoming supplies directly and to increase access to Canadian sup-

plies and additional Canadian production areas. Canada and Wyoming were the two regions most preferred by the Southern California utility parties in this proceeding.

We see significant benefits for all gas consumers in accessing a new gas supply region such as Wyoming whose producers have clearly indicated a willingness to compete for market share with our existing suppliers. In addition, any of the proposed projects linking Wyoming with California also improve our network of interstate pipeline suppliers by affording relatively easy interconnections to the British Columbia, San Juan (New Mexico/Colorado), and Alberta[18] gas producing areas.

Improved access to Canadian gas supplies appears to have a number of advantages. Imports of natural gas from Canada have proven over the last few years to be plentiful and very competitive. There is some evidence that improved access to Canadian supplies would induce even more favorable price competition. It is also clear that access to Canadian gas was a major factor in the differential between the respective average gas costs of PG&E and SoCalGas. Finally, the enormous oversubscription of interruptible capacity on PGT's existing facilities, and the full subscription of the expansion project speak eloquently of the market demand for access to Canadian gas supplies. As a long-term supply option, Canadian gas has a number of benefits for California end-users.

While Wyoming and Canadian supplies have been of greatest interest among California utilities who seek *new* gas supplies, our interest in supply diversity carries with it a strong desire to maintain close ties with our *existing* suppliers as well. The Southwest, long a major source of gas to California, consists of several producing basins, and each is important to California. We seek to maintain sufficient pipeline capacity to all these basins even as new supply routes are forged or old ones expanded. For example, we are impressed with the potential for new gas supplies from the coal seam formations in the San Juan basin of New Mexico and Colorado. These formations hold large reserves of easily deliverable gas only a short distance from mainline pipelines (which are substantially depreciated) already serving California. The potential for competitively priced supplies with long reserve lives and high deliverability is attractive. We encourage the existing pipelines serving California to continue to compete for the current and future demand in our state, and coal seam gas will play an important role in that competition.

3. *Capacity Allocation*

Firm capacity on new interstate pipeline projects should be allocated in advance, by contract, on a long-term basis to California Public Utilities Commission (CPUC)-regulated utilities and their wholesale and utility electric generation (UEG) utility customers. In addition, EOR customers willing to sign firm, long-term commitments to use and pay for interstate pipeline capacity should be accommodated as part of an overall settlement.

Some form of firm capacity brokering should be authorized on the new pipeline additions, rendering incremental firm capacity available for the benefit of both core and noncore customers.

Following the termination of any EOR producer firm capacity contracts involving new capacity additions, and subject to FERC approval, the capacity rights of such EOR customers must be capable of reallocation to the LDCs and other utilities which are firm capacity holders on the same pipeline.

[14] We have consistently supported the development of a program to "broker" or otherwise temporarily assign capacity on natural gas pipelines. Our position is unchanged. Indeed, it is bolstered by the record in this proceeding. We continue to believe that such a program is needed, that it should apply to both interstate and intrastate pipelines, and that it should be implemented on both new and existing pipelines. Our willingness to support a given interstate pipeline project continues to be conditioned on the sponsor's commitment to allow capacity brokering.

Some clarification seems necessary regarding what we mean by "capacity brokering." Where we have discussed "temporary" capacity allocation by brokering of "incremental" capacity, we meant to indicate that the holder of firm capacity rights would reassign those rights to another user of the capacity. However, another definition of capacity brokering may relate to the assignment of *primary* capacity rights, as when a pipeline proponent wishes to auction portions of a proposed pipeline. This latter definition of capacity brokering can be used to maximize the value of a pipeline and facilitate nondiscriminatory open access. While the latter is of great use for pipeline proponents to identify those that they may contract with for long-term capacity, we are referring to capacity brokering here as the reassignment of capacity rights on a temporary basis.

The current lack of capacity brokering on pipelines into and within California is a major weakness in the gas market. Without brokering (or similar means by which a holder of firm rights to pipeline capacity could temporarily transfer those rights to a third party), the market function of matching willing buyers and sellers is seriously impeded, and capacity stands idle. By giving gas purchasers access to capacity when they need it, a brokering program could increase pipeline load factors, in effect "adding" capacity. Conversely, if as we suspect, brokering alone proves to be insufficient to facilitate the intrastate transportation of gas delivered to California by new interstate pipelines, we would expect the LDCs to construct sufficient intrastate capacity to match the interstate expansions. As indicated elsewhere in this order, we would provide expedited review and approval of such intrastate capacity additions as are reasonably required.

We conclude that a properly constructed brokering program can work to the benefit of everyone concerned with the natural gas industry, including producers, transporters, and consumers. Such a program is an essential element in the "unbundled" gas industry structure that this Commission and the FERC have fostered.

We acknowledge that brokering presents practical difficulties, especially on an interstate system. There may be no single brokering program that is suitable for all pipelines. However, we note that individual interstate pipelines have cooperated with interested parties to work out brokering or other methods of capacity assignment. Thus, there is already some valuable experience with making brokering work. Also, there has recently been encouraging progress with Transwestern in proceedings ongoing before the FERC, and we urge the FERC's approval of capacity brokering on that system, should the negotiations prove successful.

We note there has been no such progress with El Paso, nor has there been any commitment by PGT to the implementation of a brokering program for *existing* PGT capacity. We can only repeat that our willingness to support projects to add pipeline capacity is contingent on the sponsor's commitment to making the most efficient use of existing as well as additional capacity. Brokering or some other appropriate method of capacity assignment is essential to efficient use of pipelines.

Our December 1988 criteria must not be interpreted as indicating a preference for the LDCs to absorb all unused pipeline capacity for the core.[19] To the extent that the criteria set forth in I.88-12-027 required LDCs and other firm capacity holders to have a right of first refusal for any EOR capacity which became available upon the termination of contracts, we modify the criteria to provide that if any capacity becomes available after the expiration of the initial capacity contracts, such capacity shall be reallocated according to a FERC-approved, non-discriminatory allocation system, such as an open season or first-come, first-served.

We no longer insist that all the capacity on a new project must be reserved for electric and wholesale utilities, EOR customers or the LDCs. We note that substantial participation by some or all of those three groups is essential for any project to be viable, but we will not oppose projects in which capacity rights are available to other types of shippers, end-users or producers.

4. *Bypass Issues*

[15] We continue to prefer that any new interstate capacity should interconnect at the state border with an intrastate pipeline sub-

ject to CPUC jurisdiction. The Commission will consider approval of FERC-regulated pipeline facilities initially dedicated to EOR use as a part of an overall settlement if the capacity of such facilities is limited to incremental EOR service or service which does not bypass the distribution utilities.

Our support for the settlement will depend on a commitment from any new pipeline project owner and operator that such a dedicated FERC-regulated EOR facility shall not be extended or expanded to bypass California LDCs to serve non-EOR customers in California, except by interconnection with existing distribution facilities subject to CPUC regulation.

5. *Jurisdictional Issues*

While new EOR-dedicated capacity may be federally regulated for an extended period of time (e.g. fifteen years) to enable EOR customers to recover a substantial portion of their investment during the period of FERC jurisdiction, after such a period of time has elapsed, jurisdiction over any new pipeline facilities constructed within the State of California must revert to CPUC jurisdiction, preferably through self-implementing arrangements which give a substantial measure of certainty that they will operate as intended in the future. We envision pre-granted abandonment of FERC authorization and arrangements to segment the ownership of facilities within and without the boundaries of the state as potential vehicles for such a jurisdictional reversion.

[16] These two sets of criteria remain the most controversial and the most important to the Commission in reaching an accommodation with pipeline project sponsors and developers. We continue to adhere to the principles set forth in these criteria, and wish to clarify their application. Initially, we restate our strongly held view, "that any new interstate capacity should interconnect at the state border with an intrastate pipeline subject to CPUC jurisdiction." This remains a clear solution to the issues of bypass and jurisdiction. It comports with the original intent of Congress in providing for split jurisdiction between the states and the federal government in the Natural Gas Act; it minimizes the likelihood of any conflict between the jurisdictions; and it has effectively functioned as a regulatory scheme in California for decades.

In I.88-12-027, we held out the possibility of support for FERC-regulated interstate projects which would be initially dedicated to EOR and utility customers as part of a settlement, if the capacity were limited to incremental EOR use, or service which does not bypass the LDC facilities. We also indicated that our support for any such project would depend on a commitment that any FERC-regulated interstate facilities within the state must revert to CPUC jurisdiction after some extended period of time.

Two recent orders of the FERC lead us to believe that the reversion of jurisdiction proposals contained in various settlements may not be feasible, or at least may not be approved by the FERC. In its Order Issuing Certificate and Amending Prior Orders in the WyCal case (Dockets No. CP90-41-000, *et al.*, issued January 24, 1990), the FERC disapproved the alternatives offered by WyCal which would have permitted a joint project with PG&E to be constructed by means of leasing PG&E-constructed facilities appurtenant to Line 300 to WyCal for a specified term of years. The FERC specifically found the proposed arrangement to violate the requirements of the Natural Gas Act. Indeed, the FERC appears to believe that the PG&E-constructed facilities would remain subject to CPUC jurisdiction and thus could not be simultaneously subject to FERC jurisdiction.

In a companion decision, Order Issuing Certificates, Granting and Denying Rehearing, and Clarifying and Modifying Prior Order, issued on January 24, 1990 in the Kern River and Mojave cases (Dockets No. CP89-2047-000 *et al.* and CP89-1-001 *et al.*), the FERC made it clear that it was only issuing certificates to Kern River and Mojave and was *not* approving the joint Kern River/Mojave/SoCalGas settlement, or approving the transfer of jurisdiction of such facilities to the CPUC. The FERC did not specifically express any opinion on the validity of SoCalGas' contractual option to purchase the in-state facilities or upon the merits of any application for pre-granted abandonment, stating that these issues were not before it at this time.

[17] In light of these orders, we cannot find that the settlement provisions submitted to the Commission by these parties will result in a transfer of in-state facilities to either utility ownership or CPUC jurisdiction. Further clarification and/or new decisions by the FERC would be required to assure this Commission that such compromise solutions to the jurisdictional issue can be effective.

We continue to feel strongly that construction of an interstate pipeline to bypass the LDCs will inevitably result in substantial cost reallocation to the captive customers. This is an improper intrusion into the wholly local issue of retail rate design. In addition, we are not satisfied with the provisions of the various settlements filed by the parties which purport to preclude non-EOR bypass. FERC has not yet approved settlement provisions which effectively restrict bypass service directly to an end user, although the settlements clearly do *permit* service to be made through the LDC through appropriate interconnections.

There are limits to how far this Commission should go in an attempt to facilitate the construction of new pipelines to California. It is one thing to countenance bypass service to the EOR market for a designated period of time as part of a compromise solution. Similarly, it is conceivable that non-EOR bypass in some limited form could be tolerated if that were the only way to expedite new capacity. However, where the proposed settlements contain no effective bar to either EOR or non-EOR bypass, and recent FERC orders give no indication that either a transfer of facilities to LDCs or a pregranted abandonment will be approved, we must conclude that the jurisdictional criteria set forth in I.88-12-027 have not been satisfied.

Considering these developments, we conclude that our support for new pipeline projects must be conditioned on a strictly objective standard for meeting the original criteria stated in I.88-12-027. Mere representations of a party's intent or understanding will not suffice. To gain Commission support, a project will have to demonstrate one of three things, either 1) a structural solution to prevent bypass, such as a configuration in which the interstate pipeline stops at the border, and a CPUC jurisdictional LDC transports the gas within the state; or 2) final FERC approval of provisions to effectively transfer jurisdiction of facilities within California to CPUC jurisdiction after a stated period of time not to exceed 20 years through pre-granted abandonment; or 3) final FERC approval of an agreement or option for the LDC to purchase the in-state facilities of the interstate pipeline during a similar time period, thus qualifying the in-state facilities for Hinshaw exemption from FERC regulation.

6. *EOR Service Issues*

Following a reversion of jurisdiction to the CPUC, EOR contracts for pipeline service will continue to be honored according to their terms for the life of the contracts, including a Commission waiver of the provisions of General Order (GO) 96-A so as to prevent the modification of existing long-term EOR contracts.

We continue to believe that the LDCs represent a viable and competitive means of service for EOR customers. However, if a pipeline project proceeds with a proposal to serve the EOR market under one of the approved scenarios described above wherein the LDC will assume control of the in-state facilities after an extended period of time (e.g. 20 years), we reassure the parties who ship gas over such pipelines that the switch in jurisdiction to the CPUC will not threaten existing transportation agreements.

Accordingly, we affirm our previous position, stated in I.88-12-027, that upon assumption of jurisdiction by the CPUC over any facilities of the pipeline projects which (1) are the subject of this order, (2) exist within the State of California, and (3) were previously interstate facilities, the CPUC will, and by this order does, waive the provisions of General Order 96-A, paragraphs IX and X (A.), thus waiving the Commission's right to modify such contracts.

We intend by this action to permit the provisions of such contracts to remain in effect for the life of the contracts in the same manner that they were implemented while the pipeline in question was under FERC jurisdiction.

7. Cost Allocation Issues

Cost responsibility for new capacity must flow to those customers who will benefit from firm service on the pipeline.. We will not place the risk of cost recovery for such facilities on core customers, except to the extent it can be conclusively demonstrated that they benefit from the new facilities. The same principles will be applied to the allocation of the costs of stranded investments and idled capacity.

[18] We likewise reaffirm our original criteria for pipeline cost allocation as set forth in I.88-12-027. Costs shall be allocated to the parties benefiting from new pipeline capacity, in direct proportion to their capacity rights on the new project. Core customers will not be reallocated any costs of existing pipelines at this time. Core customers will only bear such costs of new projects as relate to new capacity for which the LDCs contract to serve the core and which is approved by the Commission. (See also our discussion below regarding guidelines for California utility commitments for additional pipeline capacity.)

8. *Procedural Issues*

Certification, environmental review, rate design, and cost allocation of the CPUC jurisdictional portion of any proposed transmission project meeting our criteria will be conducted so that all necessary approvals can be issued in the most expeditious manner possible. To allow for such expeditious procedures, we are prepared to utilize our settlement procedures whenever possible.

Specifically, we will be prepared to provide expeditious advance review and approval of certificate applications and contracts submitted by California regulated utilities to implement a comprehensive settlement which meets the criteria set forth herein.

The CPUC will fully cooperate with the FERC and other federal authorities to encourage the issuance of expeditious certificates, environmental authorizations, and other permits required for the FERC-regulated interstate portion of any comprehensive pipeline proposals, provided that such proposals are consistent with the criteria outlined here.

The Commission remains committed to expedited consideration of all pipeline related issues, including environmental reviews and advance review and approval of utility contracts for capacity and gas supply as required to speed the construction of new pipeline capacity. We urge the utilities to finalize such agreements with pipeline sponsors whose projects meet the criteria restated in this order and to submit such contracts for review at the earliest possible time.

C. *A Review of the Proposed Pipelines Projects and The Commission's Criteria*

[1] In this section, we review the current status of the interstate pipeline proposals, as reflected in the record of this proceeding. Where applicable, we note any aspect of the individual proposals that does not *presently* conform to the conditions set forth above.[20] In noting nonconforming aspects, we neither condemn nor prefer any project. Our intention is entirely constructive: We are providing objective information to the sponsors of the various pipeline proposals, so that they will know clearly the aspects of their proposals that need further refinement to gain this Commission's support.

We do not dictate to the sponsors how to refine their projects. So long as they conform to the conditions that we have stated all along in this procceeding, they are free to do whatever they feel necessary to compete effectively, secure in the knowledge that they will have this Commission's support, both in California and before the FERC.

We single out the SoCalGas southern expansion for separate discussion as it is

Exhibit ___ (PRC-2)
Docket No. 920807-GP

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Decision 92-10-056 October 21, 1992

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

Application of PACIFIC GAS AND ELECTRIC COMPANY for a Certificate of Public Convenience and Necessity to Construct and Operate an Expansion of its Existing Natural Gas Pipeline System. (U 39 G)	Application 89-04-033 (Filed April 14, 1989)

(See Appendix A for appearances.)

INDEX

O P I N I O N

I. Summary of Decision on Rehearing

Today we reaffirm our earlier determinations in Decision (D.) 90-12-119, 39 Cal.P.U.C.2d 69 (1990), D.91-06-017 and D.91-06-053, __ Cal.P.U.C.2d __ (1991), which required incremental rate treatment for the Pacific Gas and Electric Company (PG&E) Expansion Project. We base our decision today in large part on the conclusion that the PG&E's certificate of public convenience and necessity (CPCN) granted in D.90-12-119 was not predicated on a finding of need but on our "let the market decide" policy of allowing competitive forces to determine whether pipeline capacity should be constructed and on our oft-stated conclusion that the cost of new facilities should be borne by those customers for whose benefit the facilities are constructed. We accordingly reject the contention that the cost of the PG&E Expansion should be partially or wholly "rolled-in" to the transportation rates charged to existing PG&E customers. We nevertheless leave the actual ratemaking tariffs and accounts to be proposed and adopted in the Expansion's first general rate case.

We reaffirm our intent, first expressed in D.90-12-119, that PG&E's shareholders shall bear the risk of revenue recovery for the Expansion as a condition of our "let the market decide" policy for approving PG&E's CPCN. The risks of undersubscription and underutilization of the Expansion are risks that have been undertaken by PG&E's shareholders. We will not impose those risks on PG&E's ratepayers in consideration of their receipt of small or incidental benefits from the construction of Expansion capacity. Unlike in a traditional CPCN proceeding, it is the applicant that has here undertaken to determine the need for its proposed facilities; it is therefore the applicant that must bear the consequences if its determination proves to be wrong.

We also adhere to our requirement that volumes of gas transported on the incremental PGT Expansion outside of California are subject to the incremental PG&E Expansion transportation rate within California. This requirement -- which has come to be known as the "crossover ban" because it precludes incremental volumes transported to the Oregon/California border from "crossing over" at the border to the lower intrastate existing facilities rate -- appears necessary to ensure that the cost of incremental facilities is borne by incremental customers and not by existing customers.

We further reaffirm the "postage stamp" rate for Expansion deliveries, to ensure consistency with our existing intrastate transportation rates and to avoid potentially significant administrative difficulties. The Expansion's rates will be based not on the mileage from the Oregon/California border to the point of delivery, but on the cost of the facilities that constitute the entire Expansion.

Finally, we eliminate the double recovery of charges for intrastate transportation from the Oregon/California border to load centers in California by adopting PG&E's proposal to eliminate "duplicative backbone charges" on the PG&E system.

II. Procedural History

A. Grant of Rehearing

The application of PG&E for a CPCN to construct an expansion of its natural gas pipeline facilities from Malin, at the Oregon-California border, to Kern River Station, in Kern County, was granted by D.90-12-119.[1] That decision was modified by D.91-06-017 and D.91-06-053.[2]

Rehearing of D.91-06-017 and D.91-06-053 was granted by D.91-09-035 for the purpose of examining the following issues:

1. Whether the use of incremental transportation rates for the delivery of Expansion gas within PG&E's service territory should be replaced with a system of rolled-in prices;

2. Whether D.91-06-053's prohibition against incremental loads "crossing over" from the interstate PGT Expansion system to obtain non-incremental PG&E existing system transportation rates within California should be eliminated;

3. Whether the postage stamp rate design is just and reasonable; and

4. How duplicative backbone transmission charges for northern California shippers can best be eliminated.

B. Record on Rehearing

An evidentiary hearing on rehearing issues was held from November 13 through December 13, 1991, and the record includes 119 exhibits.

1 PG&E and its interstate pipeline subsidiary, PGT currently own and operate facilities that transport natural gas from Alberta, Canada, to PG&E's service territory. The Expansion would increase the capacity of the PG&E/PGT line by looping existing facilities.

2 In D.91-06-017, the Commission confirmed the use of a statewide Expansion tariff ("postage stamp") rate based on the incremental cost of service for the entire Expansion Project. In D.91-06-053, the Commission determined that shipments on the interstate portion of PG&E's and PGT's expanded gas transmission facilities may not be transported within California at the existing PG&E transportation rate to avoid the intrastate Expansion Project tariff ("crossover ban").

Testimony and briefs which generally supported rolled-in pricing were submitted by PG&E, PGT, Indicated Expansion Shippers (IES), Canadian Transportation Customers Group (CTCG), and California Utility Shippers (CUS).

Testimony and briefs which supported retention of incremental rates were submitted by Altamont Gas Transmission Company (Altamont), Kern River Gas Transmission Company (Kern River), El Paso Natural Gas Company (El Paso), California Industrial Group, California League of Food Processors and California Manufacturers Association (collectively, CIG), California Gas Producers Association (CGPA), Toward Utility Rate Normalization (TURN), and Division of Ratepayer Advocates (DRA).

C. <u>Proposed ALJ Decision</u>

On July 28, 1992, assigned Administrative Law Judge (ALJ) Evelyn Lee, who presided at the hearing, circulated a proposed decision which adopted a partial roll-in of the costs of the Expansion into PG&E's system gas transportation rates, excluding the transportation rates charged PG&E's core class of customers. The partial roll-in would have equalized the rates of Expansion non-core and UEG customers and existing non-core and UEG customers and would thus have eliminated the need for the "crossover ban." The proposed decision also retained the "postage stamp" rate design and eliminated duplicative backbone charges.

For the reasons that follow, we reject the proposed decision insofar as it authorizes rolled-in rate treatment and eliminates the crossover ban, but we adopt the decision in all other respects.

D. <u>Procedural Matters</u>

1. <u>SMUD's Request for CPCN Modification</u>

Sacramento Municipal Utility District (SMUD), a shipper over the PGT (interstate) portion of the Expansion, expressed the concern that rolled-in pricing will impair its ability to connect directly to the Expansion and thereby avoid PG&E's LDC service.

SMUD requests a modification to the CPCN that requires PG&E (1) to permit direct connection to the Expansion and (2) to connect the Expansion directly to the Mojave Pipeline. These claims for relief are significantly beyond the scope of this proceeding on rehearing and are summarily denied.

2. **El Paso's Motions**

The motion of El Paso to file its reply brief one day out of time is granted. We believe El Paso has made the requisite showing of good cause. El Paso's reply brief is accordingly deemed filed on February 24, 1992. On the other hand, we find El Paso's motion to strike portions of the reply briefs of PG&E and IES or, alternatively, for an opportunity to present a supplemental response, to be meritless. Contrary to El Paso's assertions, the reply briefs of PG&E and IES do not create a new set of cost shift figures, and we perceive no basis for granting El Paso's motion to strike any portion of the briefs. Moreover, there is no reason to grant El Paso's alternative request for a supplemental response opportunity since it had the opportunity to address the PG&E and IES computations in its own reply brief. El Paso's motion is therefore denied.

3. **TURN's Request for Eligibility for Compensation**

TURN's timely-filed "Request for Finding of Eligibility for Compensation" pursuant to Rule 76.54 of the Commission's Rules of Practice and Procedure (Rules) is granted. TURN has shown that its participation in the proceeding would impose a significant financial hardship by satisfying both prongs of the significant financial hardship test of Rule 76.52(f).[3] We accept TURN's allegations that it represents the residential customer class and that such representation is necessary to a fair determination of the issues identified for rehearing. In this connection, we note that the DRA represents all customer classes and must therefore balance the interests of residential ratepayers against the interests of all other categories of ratepayers before it can formulate its positions. We also find that the economic interests of the individual customers represented by TURN is small in comparison to the costs of effective participation in the proceeding. Our finding of significant financial hardship will be in effect for the remainder of 1992 pursuant to Rule 76.54(a)(1). In addition, based on its summary of finances under Rule 76.54(1), we find that intervenor compensation constitutes a significant portion of TURN's discretionary income. Absent eligibility for such awards, TURN's resources would be inadequate to cover the costs of effective participation in our proceedings. Finally, TURN has provided an adequate statement of the issues that it intended to raise in the proceeding (Rule 76.54(a)(2) as well as an adequate

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3 (f) "Significant financial hardship" means both of the following:

(1) That, in the judgment of the Commission, the customer has or represents an interest not otherwise adequately represented, representation of which is necessary for a fair determination of the proceeding; and,

(2) Either that the customer cannot afford to pay the costs of effective participation, including advocate's fees, expert witness fees, and other reasonable costs of participation and the cost of obtaining judicial review, or that, in the case of a group or organization, the economic interest of the individual members of the group or organization is small in comparison to the costs of effective participation in the proceeding.

estimate of the compensation sought and a budget for its participation (Rule 76.54(a)(3) and (4)). No party responded to TURN's request for finding of eligibility for intervenor compensation. As TURN has met all of the requirements of Rule 76.54(a), it is eligible for an award of compensation in this proceeding.

III. Discussion

A. Rolled-In versus Incremental Rates

The primary issue before us in this rehearing proceeding is whether the cost of the intrastate Expansion should be rolled in to PG&E's system transportation rates or priced incrementally to Expansion shippers.

After careful consideration of the ALJ's proposed decision and extensive review of the record, we conclude that we will adhere to our policy of incremental pricing for the intrastate Expansion. In our view, the public benefits of fulfilling our long-held policy of allowing competitive market forces in appropriate circumstances to determine which and how much pipeline capacity should be constructed to serve California markets are best achieved by utilizing an incremental approach for the Expansion.

This proceeding presents a good example of Justice Holmes' aphorism that "a page of history is worth a volume of logic." New York Trust Co. v. Eisner, 256 U.S. 345, 349 (1921). In our Interstate Pipeline OII proceeding (I.88-12-027), we determined that the rates for new capacity to serve California markets should be set on an incremental basis and, assuming that the criteria we established to protect existing customers were met, that the market should decide which and how much pipeline capacity should be constructed. See generally D.90-02-016, 35 Cal.P.U.C.2d 196, 213 (1990) ("As proposed, shippers who receive transportation service through the expansion will pay the full cost of the project. Customers not utilizing any of the expansion facilities will not pay the costs of the project.").

In large part, our adoption of this "let the market decide" approach was compelled by our desire to harmonize our intrastate regulatory policy with developments in interstate gas pipeline regulation at the federal level. Under regulations established pursuant to its open access transportation rule, Order No. 436, the Federal Energy Regulatory Commission (FERC) had certificated competing interstate natural gas pipeline projects to serve California markets without the traditional showing of need required under Sections 7(c) and 7(e) of the Natural Gas Act, 15 U.S.C §§ 717f(c) and 717f(e). See, e.g., Wyoming-California Pipeline Co., FERC Docket No. CP87-479-000, certificate affirmed, California PUC v. FERC, 900 F.2d 269 (D.C.Cir. 1990), Mojave Pipeline Co., FERC Docket No. CP89-1-000, and Kern River Gas Transmission Co., FERC Docket No. CP89-2047-000. The FERC had authorized these competing projects under its then-existing optional expedited certificate (OEC) regulations, see FERC Regs., Part 157, Subpart E, 18 C.F.R. §§ 157.100-157.106 (1990), relying on the theory that the applicants were assuming the risk of project failure or underutilization and hence would not construct capacity which was not needed or desired by the market. See Associated Gas Distributors v. FERC, 824 F.2d 981, 1030-38 (D.C.Cir. 1987); California PUC v. FERC, supra, 900 F.2d at 277-80. The OEC regulations prohibited cost-shifting to customers of services other than those for which the new facilities were proposed to be constructed. See 18 C.F.R. § 157.103(d)(8) (1990).

Consistent with the FERC's OEC program and our policy established in D.90-02-016, we issued a CPCN for the PG&E Expansion in D.90-12-119, 39 Cal.P.U.C.2d 69 (1990), without subjecting the project to the traditional regulatory "need" test. Instead, we relied on PG&E's determination of market demand and placed the utility's shareholders at risk for the cost of unneeded or underutilized facilities. In the absence of a regulatory finding of "need" underlying PG&E's CPCN, it is now difficult for us to justify granting PG&E the protection that a rolled-in approach would afford, and we decline to do so.[4]

The Expansion is economically justified only to the extent that incremental shippers, and not existing ratepayers, have determined that they need the capacity it affords and have committed themselves to bearing its cost. Since PG&E has begun construction of certain segments of the Expansion based on existing signed firm transportation contracts, PG&E obviously believes the market supports the Expansion.

Incremental pricing for the Expansion serves at least two important objectives. First, as we have noted in our previous decisions, the incremental pricing of new facilities assures that those for whose benefit the facilities are constructed will bear the cost. Conversely, it assures that existing customers who have no need for such incremental facilities will not be saddled with costs or risks they have not chosen to incur. Second, we believe that under the particular circumstances presented in this proceeding our "let the market decide" policy necessitates that rates for the Expansion be established by a method which facilitates the market's making an apples-to-apples comparison of competing proposals to construct pipeline capacity and a "level playing field" among competitors. In this connection, we reject the notion that PG&E may properly recharacterize the primary

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4 In D.90-12-119, we conditioned the Expansion's CPCN on a market-based "pure incremental" allocation method using a separate Expansion rate base to ensure that PG&E's existing ratepayers would not bear any costs of the Expansion. Thereafter, in D.91-06-017, we adopted an "allocated incremental" method for the Expansion so that jointly used facilities are allocated between existing and Expansion ratepayers. We adhere to this later approach to incremental pricing.

purpose of the Expansion as serving northern California customers and then seek an alteration of rate treatment for the Expansion based on such a fundamental recharacterization. It is not the purpose of this rehearing proceeding to relitigate the fundamental theory on which PG&E's CPCN is predicated. Under our policy, the need for the Expansion for which the CPCN was granted is best tested by ascertaining whether there is a sufficient market committed to the project to pay its incremental cost.

We perceive no undue discrimination in the distinction we make between customer classes. We find it entirely appropriate that existing customers who have no clear need for new facilities and will receive little or no benefit from such facilities should be protected from bearing the cost of those facilities. We find it equally appropriate that incremental customers who need the new facilities and will use them should pay for them. We find that the incremental nature of these customers is amply demonstrated both from the customers' willingness to enter into Expansion contracts to pay the incremental rate and from their utilization of the incremental interstate PGT Expansion facilities to transport their volumes to the Oregon/California border.

DRA argues that many of the Expansion contracts with northern California delivery points give PG&E the option of offering the relevant customers the "economic equivalent" of rolled-in pricing for a five-year period. Asserting that under such contracts the shippers must accept such an offer if it is made, DRA expresses the concern that PG&E would exercise this right and then seek full recovery of Expansion costs from non-Expansion ratepayers. We find that PG&E's contractual assumption of the difference between rolled-in rates or their "economic equivalent" and incremental rates is fully consistent with our previous assignment of market risk to PG&E's shareholders in D.90-12-119. We will not countenance any attempt by PG&E to collect that rate differential from ratepayers using existing facilities in a subsequent proceeding. If PG&E must discount its rates below incremental cost in order to maximize the revenues it recovers from capacity it has voluntarily chosen to construct, the revenue shortfall thus occasioned may not be recovered from core customers or other existing customers who have little or no need for the newly constructed facilities.

PG&E's witness testified that PG&E had assumed the risk of underutilization only at the commencement of construction and thus PG&E may attempt to pass on the cost of underutilization in subsequent Commission proceedings. We take exception to this testimony. We have given PG&E the discretion to undertake construction of the Expansion at its shareholders' risk, premised on PG&E's assessment of the need for the Expansion. In the absence of a truly extraordinary showing, based on clear and convincing evidence that the public interest so requires, we will reject out of hand any attempts by PG&E to pass on the costs of underutilization of constructed facilities to existing customers in subsequent Commission proceedings. A contrary ruling would unduly undercut our "let the market decide" policy and would inappropriately relieve PG&E of the responsibility for its market-based decisionmaking.

In D.90-12-119, we emphasized that existing ratepayers should not be burdened with the risk of underutilization or undersubscription of the Expansion. We adhere to that view. Thus PG&E may recover no more than its Expansion cost of service times the ratio of throughput subject to firm transportation contracts to the total firm transportation capacity of the Expansion. We will protect non-Expansion ratepayers from subsidizing Expansion transportation rates where PG&E is unable to fill Expansion capacity or must discount the incremental transportation rates to do so. As provided in D.90-12-119, PG&E remains free to collect the revenues not included in firm contracts by providing interruptible service on the Expansion and the appropriate cost for that service is to be determined in the first general rate case for the Expansion Project.

Our treating the PG&E Expansion as a project intended to benefit incremental shippers is fully consistent not only with the assumptions underlying our grant of a CPCN and our "let the market decide" policy but with the FERC's treatment of the corresponding interstate Expansion by PGT. The PGT Expansion will have incrementally-based initial rates and its delivery capacity to the Oregon/California border will be precisely matched to the take-away capacity of the PG&E Expansion. Moreover, incremental pricing appears fully consistent with FERC policies in other cases. For example, in Great Lakes Gas Transmission Limited Partnership, 57 FERC ¶ 61,140 (1991), rehearing pending, the FERC rejected rolled-in rates because such an approach would have resulted in the existing customers cross-subsidizing the proposed expansion project. And in Algonquin Gas Transmission Co. v. FERC, 948 F.2d 1305, 1312-14 (D.C.Cir. 1991), the U.S. Court of Appeals for the D.C. Circuit held that rolled-in treatment cannot be justified by conclusionary assertions and may only be utilized where there is substantial evidence that expansion facilities will provide specific, system-wide benefit. We do not believe such a showing has been made here.[5]

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5 True, in Northwest Pipeline Corp., 59 FERC ¶ 61,289 (1992), the FERC issued a declaratory order authorizing Northwest to utilize rolled-in rates for a proposed expansion, but that case is plainly distinguishable. There the FERC noted that the expansion alleviated specific existing capacity constraints which had limited Northwest's ability to meet the full contract demand of its existing customers. Id., at p. 62,057. The FERC also relied on the fact that all but one of Northwest's existing firm transportation customers either supported or did not oppose rolled-in pricing, which resulted in an increase in firm transportation rates of approximately $.05/MMBtu. Id., at p. 62,058. Notably,

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Moreover, as the FERC has correctly observed on several occasions, see, e.g., Pacific Gas Transmission Co., 56 FERC ¶ 61,192 (1991), at pp. 61,699, 61,711-12; Pacific Gas Transmission Co., 57 FERC ¶ 61,097 (1991), at p. 61,360, our resolution of the "incremental versus rolled-in" issue for the intrastate Expansion is one within our exclusive jurisdiction under the Hinshaw Amendment to the Natural Gas Act, 15 U.S.C. § 717(c). Thus, despite our desire and considerable effort to harmonize our regulation of the intrastate PG&E Expansion with FERC regulation of the corresponding interstate PGT Expansion, we are required in the final analysis to resolve this issue of "essentially local concern" based on our state perspective as to what constitutes "just and reasonable" rate treatment for the intrastate Expansion. We have conscientiously attempted to do so in this decision.

B. Disposition of Crossover Ban

We also adhere to our requirement that volumes of gas transported on the incremental PGT Expansion outside of California are subject to the incremental PG&E Expansion transportation rate within California. This requirement -- which has come to be known as the "crossover ban" because it precludes incremental volumes transported to the Oregon/California border from "crossing over" at the border to the lower intrastate existing facilities rate --

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(Footnote continued from previous page)
the FERC stated that its decision was "limited to the specific circumstances and facts" presented in that case. Id.

The narrowness of the Northwest decision and the fact that it does not alter the FERC's incremental rate policy is confirmed by the FERC's decision in Colorado Interstate Gas Company (CIG), 59 FERC ¶ 61,364 (1992), decided 21 days after Northwest. In CIG, the FERC explicitly denied CIG's request on rehearing for pre-approval of rolled-in rate treatment for its project.

appears necessary, in the absence of assigned property rights for existing intrastate facilities, to ensure that the cost of incremental facilities is borne by incremental customers and not by existing customers. Notably, the only gas volumes to which the crossover ban would apply are those clearly-incremental volumes which have reached the PG&E system through the incremental (and incrementally-priced) PGT Expansion facilities.

We stress that the crossover ban in no way connotes a limitation on a shipper's physical access to particular facilities; the PG&E Expansion facilities will be fully integrated with the existing PG&E system and gas will flow through a single expanded intrastate system. What the crossover ban does connote, however, is our determination that different classes of customers will pay different rates. Such a determination is hardly extraordinary. We commonly establish economic classifications for ratemaking purposes, and our determinations are uniformly upheld by the California Supreme Court so long as there is "a reasonable relationship between the classifications drawn and the purpose for which they are made." E.g., Wood v. Public Utilities Comm'n, 4 Cal.3d 288, 294 (1971); Toward Utility Rate Normalization v. Public Utilities Comm'n, 22 Cal.3d 529, 544 (1978). We believe that our commonly-drawn distinction between incremental and existing customers, which serves our "let the market decide" policy and assures that the cost responsibility for new facilities should be allocated to those who benefit from the facilities, plainly meets this standard.

The crossover ban is merely a feature of our incremental rate design which is intended to ensure that existing customers are not forced to pay for incremental facilities which are not being constructed primarily for their benefit. As previously noted, PGT's existing system delivery capability to Malin at the Oregon/California border is matched precisely to PG&E's existing take-away capability at Malin, and PGT's Expansion delivery capability to Malin is matched precisely to PG&E's Expansion take-away capability at Malin. There is clearly insufficient capacity on the existing PG&E system to receive and transport on a firm basis incremental volumes transported over the PGT Expansion without the construction of the PG&E Expansion. Without a requirement such as the crossover ban, some incremental volumes would surely "migrate" to existing facilities, potentially forcing non-Expansion customers to utilize and pay for PG&E Expansion facilities. Without a requirement such as the crossover ban, our incremental rate design, and our policy that incremental facilities be paid for by the customers for whose benefit they are constructed, would be largely unenforceable.

It has been suggested by some that the crossover ban may constitute an unlawful tying arrangement in violation of the federal antitrust laws. To the contrary, the crossover ban is merely a legitimate exercise of our exclusive authority over the "rates, services and facilities" of a Hinshaw Pipeline under the Hinshaw Amendment to the Natural Gas Act, 15 U.S.C § 717(c). The crossover ban merely constitutes a rate design and cost allocation methodology which enables PG&E, a state-regulated public utility, to recover its costs consistently with our regulatory policy. The circumstances involved here simply do not establish an unlawful tying arrangement in violation of the antitrust laws. See, e.g., Jefferson Parish Hosp. Dist. v. Hyde, 466 U.S. 2, 12 (1984); Times-Picayune Pub. Co. v. United States, 345 U.S. 594, 614 (1953); Jack Walters & Sons Corp. v. Morton Bldg., Inc., 737 F.2d 698, 703 (7th Cir. 1984); Washington Gas Light Co. v. Virginia Elec. & Power Co., 438 F.2d 248, 253 (4th Cir. 1971).

Moreover, the State of California has a compelling interest in the fair and effective regulation of its public utilities. See, e.g., Pacific Gas & Elec. Co. v. Public Utilities Comm'n of California, 475 U.S. 1, 19 (plur. opin.), 25 (opin of Marshall, J.) (1986); Pacific Gas & Elec. Co. v. Energy Resources

Comm'n of California, 461 U.S. 190, 205 (1983), and cases there cited. And the conduct of PG&E in accordance with our clearly articulated state policy and under our active supervision is exempt from the federal antitrust laws under the state action doctrine. See, e.g., Southern Motor Carriers Rate Conf. v. United States, 471 U.S. 48, 63-64 (1985); Arkansas Elec. Coop. Corp. v. Arkansas Public Service Comm'n, 461 U.S. 375, 390-95 (1983); Parker v. Brown, 317 U.S. 341 (1943); Washington Gas Light Co., supra, 438 F.2d at 251-52.

In our view, no adequate justification for elimination of the crossover ban has been shown, and we therefore adhere to that requirement.

C. Retention of Postage Stamp Rate Design

We reaffirm our "postage stamp" rate design for Expansion deliveries. Virtually all unbundled gas transportation rates in California are "postage stamp" rates. Our adherence to a "postage stamp" rate design will ensure consistency with our existing intrastate transportation rates and avoid significant administrative difficulties in establishing and overseeing a mileage-based system. Moreover, it is not clear that the administrative difficulties of establishing mileage-based rates or northern California/southern California differential cost-based rates for the Expansion would result in a real difference from "postage stamp" rates since the vast majority of Expansion facilities are situated north of Panoche Junction, California.

In D.91-06-017, we found that "the interests of all ratepayers in this state would be served by allocating efficiencies of scale and scope to incremental users of natural gas in southern California," id., at 13, and that the "postage stamp" rate is "supported by public policy promoting economic development of the state as a whole," id. We reaffirm those findings.

We also find persuasive in this case the arguments of some parties to the effect that distance is not a reasonable proxy for cost responsibility for the Expansion, since there is no direct relationship between distance and cost incurrence. In addition, we agree that other factors, including the operation of the Expansion and PG&E's existing backbone transmission system as an integrated pipeline system, the fact that Expansion supplies could physically flow either north or south from Panoche Junction and the use of displacement as a primary means of delivering Expansion gas to southern California, undermine any direct relationship between distance and cost and thus would likely make a mileage-based system the subject of charges of irrationality and discrimination. On balance, we see no strong justification for altering our "postage stamp" approach at this time, and we believe that such a change to our existing transportation rate structure could create significant administrative, measurement and verification problems for the Commission, for PG&E and for Expansion shippers.

We therefore reaffirm the "postage stamp" approach. Expansion service, like all transportation service provided by California's state-regulated LDCs, will be priced on a uniform statewide basis, and Expansion service to southern California will be priced the same as service to northern California.

We wish to make clear, however, that the "postage stamp" rate design does not connote a limitation on a northern California shipper's ability to receive gas at any delivery point of its choosing. However, an Expansion shipper's rates will be predicated not on the mileage from the Oregon/California border to the point of delivery but on the cost of the facilities that constitute the entire Expansion.

D. Elimination of Duplicative Backbone Charges

In our earlier decisions, we identified the problem of northern California Expansion shippers having to pay the "postage stamp" rate and an additional existing system transportation charge to cover the cost of re-transporting the gas from the Kern River Station terminus of the Expansion to the northern California delivery point. The duplicative charges we refer to involve mainline or "backbone" transportation charges but not local distribution charges specific to the particular delivery point involved. The inclusion of duplicative backbone demand charges in the rates for Expansion deliveries to northern California would cause Expansion customers to incur costs for facilities that they do not use. Moreover, although we have determined to retain "postage stamp" rather than mileage-based rates for Expansion deliveries, our adherence to these duplicative backbone transportation charges would create the anomaly of PG&E's recovering more from some customers whose deliveries necessitate contruction of less than all of the Expansion facilities than from customers whose deliveries require the construction of all Expansion facilities. We have long been sensitive to the inequitable nature of these duplicative charges, and we take this opportunity to remove them from the transportation rates for northern California Expansion deliveries. We find merit in PG&E's proposed method for eliminating duplicative backbone charges, and we adopt that method. Should problems arise necessitating modification of that method, we will consider any such problems and any proposed mechanisms to correct them in the Expansion's first general rate case.

IV. Conclusion

In sum, we conclude that incremental pricing will continue to be utilized for firm transportation of natural gas over the PG&E Expansion. The crossover ban will remain in place, since we view that ratemaking classification requirement as being necessary to protect incremental rates, to further our "let the market decide" policy and to ensure that customers for whose benefit the Expansion is constructed assume its cost. We will retain the Expansion's postage stamp rate design for reasons of administrative convenience, to ensure consistency with other transportation rates used in California and because the PG&E gas distribution system will operate in a physically integrated manner after the Expansion begins operation. Finally, we prevent PG&E's recovery of duplicative backbone transmission charges for northern California Expansion shippers by adopting the utility's proposed backbone transmission charge methodology.

V. Related Petitions

A. Joint Petition of Edison and SDG&E for Clarification of D.92-03-086 in A.89-04-033

In their Joint Petition for Clarification of D.92-03-086, Edison and SDG&E have asked us to clarify that any loss of subscription on the Expansion that occurs because of a shipper's exercise of a contractual "out" will not result in a shift of additional Expansion costs to other Expansion shippers. Petitioners claim that those volumes should be treated as "unsubscribed volumes" such that PG&E would bear the burden of those revenues.

We clarify that by PG&E's undertaking construction of the Expansion, its shareholders have assumed the risks of undersubscription and underutilization of the Expansion. PG&E cannot shift those risks on to Expansion shippers or other PG&E ratepayers by means of contracts which absolve the contracting parties of penalties for nonperformance due to a failure of their economic expectations to materialize.

The revenue mechanisms for this rate burden will be addressed in the Expansion's rate case proceeding. Today's disposition of the Joint Petition is entirely consistent with our adoption, and PG&E's embrace, of a "let the market decide" approach for the Expansion. The Joint Petition of Edison and SDG&E is granted.

B. Joint Petition of the DRA and TURN for Modification of D.92-03-086 and for Emergency Stay

The Joint Petition of DRA and TURN for Modification of D.92-03-086 and for Emergency Stay is denied. We are concerned that the additional access to interstate capacity will decrease the value of interstate capacity held by PG&E and other California LDCs. If an LDC does not make use of that capacity, pre-existing capacity held by the LDC will become "stranded capacity." The burden of excess interstate capacity must be weighed against the benefit of increased gas-to-gas competition before the Commission can judge the reasonableness of LDC subscription to Expansion capacity. That analysis will be undertaken in the appropriate gas reasonableness review.

As noted by DRA and TURN, we have an ongoing proceeding to implement capacity brokering. Furthermore, the capacity procurement decisions of Edison and SDG&E are subject to reasonableness review. This decision further delimits the ability of PG&E to assign the burden on Expansion underutilitization to ratepayers. Thus, sufficient safeguards of ratepayer interests already exist so that a stay of the Expansion CPCN is not necessary on the grounds asserted by DRA and TURN.

C. Petition of Conoco, et al. to Intervene

The Petition of Conoco, Inc., Meridian Oil, Inc., Texaco, Inc., and Union Pacific Fuels, Inc. to Intervene is denied. The petitioners, domestic producers of natural gas who have been actively involved in R.90-02-008, R.88-08-018, and A.90-03-039, seek a stay of construction of the PG&E Expansion, citing the same reasons as those advanced by the Southwest suppliers in response to the Joint Petition of Edison and SDG&E.

The petition is tardy, its sole purpose is to interject into this proceeding an issue not identified for rehearing, and if granted it would likely result in a presentation unnecessarily cumulative to that of other similarly-situated parties. We have already entertained and denied three separate requests for a stay of the Expansion CPCN. It would be unreasonable to revisit a CPCN each time a competitor suggested an alternative to the project for which the CPCN had been granted.

Findings of Fact

1. Rehearing of D.91-06-017 and D.91-06-053 was granted by D.91-09-035 for the purpose of examining the following issues:

   1. Whether the use of incremental rates for the delivery of Expansion gas within PG&E's service territory should be replaced with a system of rolled-in prices;

   2. Whether D.91-06-053's prohibition against crossover from the Expansion system to the existing system should be eliminated;

   3. Whether the postage stamp rate is just and reasonable; and

   4. How duplicative backbone transmission charges for northern California shippers can best be eliminated.

2. The request of SMUD for a modification to the CPCN that would require PG&E (a) to permit direct connection to the Expansion and (b) to connect the Expansion directly to the Mojave Pipeline is beyond the scope of this rehearing proceeding.

3. TURN timely filed its "Request for Finding of Eligibility for Compensation" pursuant to Rule 76.54 on January 27, 1992.

4. TURN has met both prongs of the significant financial hardship test, since TURN represents the residential customer class, which would not otherwise be adequately represented in this proceeding, and the economic interest of the individual customers represented by TURN is small in comparison to the costs of effective participation in the proceeding.

5. Absent eligibility for intervenor compensation awards, TURN's resources would be inadequate compared to the costs of effective participation in Commission proceedings.

6. TURN has opposed PG&E's proposal for partial rolled-in rate treatment for the Expansion Project; this and other issues have been detailed in TURN's testimony.

7. TURN has estimated a budget of approximately $60,000, based on its estimate of attorney time, the attorney's hourly rate, and other incidental expenses.

8. TURN has met all of the requirements of Rule 76.54(a) and is eligible for an award of compensation in this proceeding.

9. El Paso has shown good cause for the late-filing of its Reply Brief.

10. There is no basis for granting El Paso's motion to strike portions of the Reply Briefs of PG&E and IES because those briefs do not create a new set of cost shift figures.

11. There is no reason to grant El Paso's alternative request for relief, that is, an order establishing an additional round of briefing or a reopening of the record because El Paso had the opportunity to address the issue of cost shifts in its own reply brief.

12. It is appropriate to retain incremental pricing as a market test for the PG&E Expansion.

13. The public benefits of fulfilling our long-held policy of allowing competitive market forces in appropriate circumstances to determine which and how much pipeline capacity should be constructed to serve California markets are best achieved by utilizing an incremental approach for the Expansion.

14. Consistent with the FERC's OEC program and our policy established in D.90-02-016, we issued a CPCN for the PG&E Expansion in D.90-12-119 without subjecting the project to the traditional regulatory "need" test.

15. In the absence of a regulatory finding of "need" underlying PG&E's CPCN, it is inappropriate for us to grant PG&E the protection that a rolled-in approach would afford.

16. The Expansion is economically justified only to the extent that incremental shippers, and not existing ratepayers, have determined that they need the capacity it affords and have committed themselves to bearing its cost.

17. Incremental pricing for the Expansion assures that those for whose benefit the facilities are constructed will bear the cost.

18. Incremental pricing for the Expansion assures that existing customers who have no need for such incremental facilities will not be saddled with costs or risks they have not chosen to incur.

19. Incremental pricing for the Expansion is consistent with our "let the market decide" policy and results in rates for the Expansion being established by a method which facilitates the market's making an apples-to-apples comparision of competing proposals to construct pipeline capacity as well as a "level playing field" among competitors.

20. PG&E may not properly recharacterize the primary purpose of the Expansion as serving northern California customers and then seek an alteration of rate treatment for the Expansion based on such a fundamental recharacterization.

21. It is not the purpose of this rehearing proceeding to relitigate the fundamental theory on which PG&E's CPCN is predicated.

22. Under our policy, the need for the Expansion for which the CPCN was granted is best tested by ascertaining whether there is a sufficient market committed to the project to pay its incremental cost.

23. There is no undue discrimination in the distinction we make between customer classes.

24. It is appropriate that existing customers who have no clear need for new facilities and will receive little or no benefit from such facilities should be protected from bearing the cost of those facilities.

25. It is appropriate that incremental customers who need the new facilities and will use them should pay for them.

26. The incremental nature of these customers is amply demonstrated both from the customers' willingness to enter into Expansion contracts to pay the incremental rate and from their utilization of the incremental interstate PGT Expansion facilities to transport their volumes to the Oregon/California border.

27. Incremental pricing for the PG&E Expansion is just and reasonable.

28. PG&E's shareholders have commenced construction of the Expansion at their own risk in response to what they perceive to be the market's interest.

29. PG&E's contractual assumption of the difference between rolled-in rates or their "economic equivalent" and incremental rates is fully consistent with our previous assignment of market risk to PG&E's shareholders in D.90-12-119.

30. We will not countenance any attempt by PG&E to collect that rate differential from ratepayers using existing facilities in a subsequent proceeding.

31. If PG&E must discount its rates below incremental cost in order to maximize the revenues it recovers from capacity it has voluntarily chosen to construct, the revenue shortfall thus occasioned may not be recovered from core customers or other existing customers who have little or no need for the newly constructed facilities.

32. In the absence of a truly extraordinary showing, based on clear and convincing evidence that the public interest so requires, we will reject out of hand any attempts by PG&E to pass on the

costs of underutilization of constructed facilities to existing customers in subsequent Commission proceedings.

33. Existing ratepayers should not be burdened with the risk of underutilization or undersubscription of the Expansion.

34. PG&E may recover no more than its Expansion cost of service times the ratio of throughput subject to firm transportation contracts to the total firm transportation capacity of the Expansion.

35. We will protect non-Expansion ratepayers from subsidizing Expansion transportation rates where PG&E is unable to fill Expansion capacity or must discount the incremental transportation rates to do so.

36. PG&E remains free to collect the revenues not included in firm contracts by providing interruptible service on the Expansion and the appropriate cost for that service is to be determined in the first general rate case for the Expansion Project.

37. We are required to resolve the issue of incremental versus rolled-in rates based on our state perspective as to what constitutes just and reasonable rate treatment for the intrastate Expansion.

38. The rate classification requirement which has come to be known as the "crossover ban" appears necessary to ensure that the cost of incremental facilities is borne by incremental customers and not by existing customers.

39. The only gas volumes to which the crossover ban would apply are those clearly-incremental volumes which have reached the PG&E system through the incremental (and incrementally-priced) PGT Expansion facilities.

40. The crossover ban in no way connotes a limitation on a shipper's physical access to particular facilities; the PG&E Expansion facilities will be fully integrated with the existing PG&E system and gas will flow through a single expanded intrastate system.

41. The crossover ban does connote that different classes of customers will pay different rates.

42. Such a determination is hardly extraordinary; we commonly establish economic classifications for ratemaking purposes, and our determinations are uniformly upheld by the California Supreme Court so long as there is "a reasonable relationship between the classifications drawn and the purpose for which they are made."

43. Our commonly-drawn distinction between incremental and existing customers which serves our "let the market decide" policy and assures that the cost responsibility for new facilities will be allocated to those who benefit from the facilities.

44. The crossover ban is merely a feature of our incremental rate design which is intended to ensure that existing customers are not forced to pay for incremental facilities which are not being constructed primarily for their benefit.

45. PGT's existing system delivery capability to Malin at the Oregon/California border is matched precisely to PG&E's existing take-away capability at Malin, and PGT's Expansion delivery capability to Malin is matched precisely to PG&E's Expansion take-away capability at Malin.

46. There is insufficient capacity on the existing PG&E system to receive and transport on a firm basis incremental volumes transported over the PGT Expansion without the construction of the PG&E Expansion.

47. Without a requirement such as the crossover ban, some incremental volumes would "migrate" to existing facilities, potentially forcing non-Expansion customers to utilize and pay for PG&E Expansion facilities.

48. Without a requirement such as the crossover ban, our incremental rate design, and our policy that incremental facilities be paid for by the customers for whose benefit they are constructed, would be largely unenforceable.

49. The crossover ban does not constitute an unlawful tying arrangement in violation of the federal antitrust laws; it is merely a legitimate exercise of our exclusive authority over the "rates, services and facilities" of a Hinshaw Pipeline under the Hinshaw Amendment to the Natural Gas Act, 15 U.S.C § 717(c).

50. The crossover ban merely constitutes a rate design and cost allocation methodology which enables PG&E, a state-regulated public utility, to recover its costs consistently with our regulatory policy.

51. The State of California has a compelling interest in the fair and effective regulation of its public utilities.

52. The conduct of PG&E in accordance with our clearly articulated state policy and under our active supervision is exempt from the federal antitrust laws under the state action doctrine.

53. No adequate justification for elimination of the crossover ban has been shown, and continuation of the ban is just and reasonable.

54. Our "postage stamp" rate design for Expansion deliveries is just and reasonable.

55. Virtually all unbundled gas transportation rates in California are "postage stamp" rates.

56. Our adherence to a "postage stamp" rate design will ensure consistency with our existing intrastate transportation rates and avoid significant administrative difficulties in establishing and overseeing a mileage-based system.

57. It is not clear that the administrative difficulties of establishing mileage-based rates or northern California/southern California differential cost-based rates for the Expansion would result in a real difference from "postage stamp" rates since the vast majority of Expansion facilities are situated north of Panoche Junction, California.

58. The interests of all ratepayers in this state would be served by allocating efficiencies of scale and scope to incremental

users of natural gas in southern California, and the "postage stamp" rate is supported by public policy promoting economic development of the state as a whole.

59. Distance is not a reasonable proxy for cost responsibility for the Expansion, since there is no direct relationship between distance and cost incurrence.

60. Other factors, including the operation of the Expansion and PG&E's existing backbone transmission system as an integrated pipeline system, the fact that Expansion supplies could physically flow either north or south from Panoche Junction and the use of displacement as a primary means of delivering Expansion gas to southern California, undermine any direct relationship between distance and cost and thus would likely make a mileage-based system the subject of charges of irrationality and discrimination.

61. Alteration of our existing transportation rate structure could create significant administrative, measurement and verification problems for the Commission, for PG&E and for Expansion shippers.

62. Expansion service, like all transportation service provided by California's state-regulated LDCs, will be priced on a uniform statewide basis, and Expansion service to southern California will be priced the same as service to northern California.

63. The "postage stamp" rate design does not connote a limitation on a northern California shipper's ability to receive gas at any delivery point of its choosing; however, an Expansion shipper's rates will be predicated not on the mileage from the Oregon/California border to the point of delivery but on the cost of the facilities that constitute the entire Expansion.

64. Elimination of duplicative backbone charges for Expansion shippers is just and reasonable.

65. The duplicative charges we refer to involve mainline or "backbone" transportation charges but not local distribution charges specific to the particular delivery point involved.

66. The inclusion of duplicative backbone demand charges in the rates for Expansion deliveries to northern California would cause Expansion customers to incur costs for facilities that they do not use.

67. Our adherence to these duplicative backbone transportation charges would create the anomaly of PG&E's recovering more from some customers whose deliveries necessitate contruction of less than all of the Expansion facilities than from customers whose deliveries require the construction of all Expansion facilities.

68. We find merit in PG&E's proposed method for eliminating duplicative backbone charges, and we adopt that method.

69. Should problems arise necessitating modification of that method, we will consider any such problems and any proposed mechanisms to correct them in the Expansion's first general rate case.

70. The Commission's grant of CPCN in D.90-12-119 considered alternatives to the PG&E Expansion under the mandates of CEQA. The determination of alternatives to the PG&E Expansion is not a matter for which rehearing was granted.

71. Ratemaking for Expansion service should be guided by the policies announced in D.90-02-016.

72. The need for Expansion service will continue to be shown by market demand for incrementally priced Expansion service.

73. Consistent with D.90-12-119, we find that need for the Expansion has not been shown for any firm capacity beyond that governed by executed contracts for firm transportation.

74. The FERC's ultimate choice between rolled-in or incremental treatment of PGT Expansion costs cannot be predicted

and should not form the basis of this Commission's ratemaking decision on intrastate Expansion costs.

75. The Expansion was not subjected to a cost-benefit test prior to the issuance of its CPCN because the Commission allowed PG&E to respond to the market's need for the Expansion.

76. Under the facts shown here, incremental rates do not unduly discriminate between existing and new transportation customers.

77. PG&E should not be permitted to pass the risk of undersubscription, including the risk represented by the "option out" and "economic equivalent of rolled-in pricing" clauses in some of its firm transportation contracts with Expansion shippers, from its shareholders to its ratepayers.

78. PG&E should not be permitted to pass the risk of underutilization from its shareholders to ratepayers, whether by discounting Expansion firm transportation rates, forecasting error, or other means which result in a less than full rate recovery of the cost of service allocated transportation in D.90-12-119.

79. D.90-12-119 did not foreclose consideration of any proposal that revenues from interruptible transportation may be retained by shareholders.

<u>Conclusions of Law</u>

1. The PG&E Expansion should be characterized as an incremental intrastate natural gas pipeline.

2. The "let the market decide" approach adopted by D.90-02-116 for Commission approval of the PG&E Expansion is applicable to Expansion service.

3. It is reasonable to eliminate the double charge for transmission over the PG&E Expansion and its existing counterpart, PG&E Line 400 ("duplicative backbone charge").

4. It is reasonable to retain non-distance sensitive rates for Expansion transportation within PG&E's service territory and for Expansion service to southern California.

5. Our finding that TURN has met the significant financial hardship test in this proceeding will be in effect for the remainder of 1992, as provided in Rule 76.54(a)(1).

6. It is just and reasonable that incremental pricing continue to be utilized for firm transportation of natural gas over the PG&E Expansion.

7. It is just and reasonable that the crossover ban remain in place, since we view that ratemaking classification requirement as being necessary to protect incremental rates, to further our "let the market decide" policy and to ensure that customers for whose benefit the Expansion is constructed assume its cost.

8. It is just and reasonable to retain the Expansion's postage stamp rate design for reasons of administrative convenience, to ensure consistency with other transportation rates used in California and because the PG&E gas distribution system will operate in a physically integrated manner after the Expansion begins operation.

9. It is just and reasonable to prevent PG&E's recovery of duplicative backbone transmission charges for northern California Expansion shippers by adopting the utility's proposed backbone transmission charge methodology.

10. The joint petition of Edison and SDG&E for clarification of D.92-03-086 and A.89-04-033 should be granted.

11. The joint petition of DRA and TURN for modification of D.92-03-086 and request for emergency stay should be denied.

12. The petition of Conoco, Inc., Meridian Oil, Inc., Texaco, Inc., and Union Pacific Fuels to intervene should be denied.

O R D E R

IT IS ORDERED that:

1. Pacific Gas and Electric Company (PG&E) shall retain the allocated incremental rate design, the crossover ban, and postage stamp rates for its Expansion Project, as set forth in our previous decisions.

2. PG&E's methodology for eliminating duplicative backbone charges is adopted in principle.

3. PG&E will present testimony at the time of the Expansion's first general rate case concerning whether its method has effectively eliminated such duplicative charges.

4. The motion of El Paso Natural Gas Company (El Paso) to accept its reply brief one day out of time is granted. El Paso's reply brief is deemed to have been filed on February 24, 1992.

5. The motion of El Paso to strike portions of the reply briefs of PG&E and the Indicated Expansion Shippers is denied. The alternative request of El Paso for an order establishing an additional round of briefing or reopening of the record is also denied.

6. The request of Sacramento Municipal Utility District for a modification to the certificate of public convenience and necessity require PG&E (a) to permit direct connection to the Expansion and (b) to connect the Expansion directly to the Mojave Pipeline is denied.

7. Toward Utility Rate Normalization (TURN) has met all of the requirements of Rule 76.54(a) and is eligible for an award of compensation in this proceeding. Our finding that TURN has met the significant financial hardship test will be in effect during 1992.

8. The "Joint Petition of Southern California Edison Company and San Diego Gas and Electric Company for Clarification of Decision 92-03-086" is granted.

9. The "Joint Petition of the Division of Ratepayer Advocates and Toward Utility Rate Normalization for Modification of Decision 92-03-086 and Request for Emergency Stay" is denied.

10. The "Petition of Conoco, Inc., Meridian Oil, Inc., Texaco, Inc., and Union Pacific Fuels, Inc. to Intervene" is denied.

This order becomes effective 30 days from today.

Dated October 21, 1992, at San Francisco, California.

DANIEL Wm. FESSLER
President
JOHN B. OHANIAN
PATRICIA M. ECKERT
NORMAN D. SHUMWAY
Commissioners

I will file a written concurring opinion.

/s/ PATRICIA M. ECKERT
Commissioner

SUNSHINE GAS PIPELINE COMPANY

PRO FORMA STATEMENT OF INCOME

(000'S OMITTED)

LINE NO.	DESCRIPTION (col. 1)	1995 (col.2)	1996 (col.3)	1997 (col.4)	1998 (col.5)	1999 (col.6)	2000 (col.7)	2001 (col.8)
1	Operating Revenue	$47,813	$47,813	$47,813	$81,350	$105,304	$105,304	$105,304
	Operating Expenses:							
2	Operation and Maintenance	3,500	3,500	3,500	5,200	6,800	6,800	6,800
3	Depreciation-MDQ Capacity Methodology	8,587	8,587	8,587	19,147	27,333	27,333	27,333
4	Regulatory Asset-Levelized Depreciation	6,526	8,715	11,984	(16,486)	(32,638)	(30,075)	(27,451)
5	Regulatory Asset-Deferred Cost/Recovery	(35,423)	(42,019)	(49,823)	(22,193)	776	927	1,092
6	Other Taxes	9,192	9,192	9,192	12,852	14,625	13,713	12,858
7	Total Operating Expenses	($7,618)	($12,025)	($16,560)	($1,481)	$16,896	$18,698	$20,631
8	EBIT	$55,431	$59,838	$64,374	$82,830	$88,409	$86,606	$84,673
	Less:							
9	Interest Expense	29,991	29,991	29,991	38,438	41,463	40,456	39,078
10	Federal and State Inc Tax	9,669	11,342	13,069	16,722	17,632	17,349	17,157
11	Net Income	$15,771	$18,505	$21,314	$27,670	$29,314	$28,801	$28,438

Exhibit 10

Exhibit ___ (PRC-3)
Docket No. 920807-GP

SUNSHINE GAS
PIPELINE COMPANY
PRO FORMA BALANCE SHEET
(000'S OMITTED)

LINE NO.	DESCRIPTION (Col. 1)	1995 (Col. 2)	1996 (Col. 3)	1997 (Col. 4)	1998 (Col. 5)	1999 (Col. 6)	2000 (Col. 7)	2001 (Col. 8)
	ASSETS AND OTHER DEBITS							
1	PLANT	$437,540	$437,500	$565,400	$618,900	$618,900	$618,900	$618,900
2	LESS: ACC. DEPRECIATION	8,587	17,173	25,760	44,907	72,240	99,573	126,906
3	REG. ASSET-LEVELIZED DEPR.	6,5[illegible]	15,242	27,226	10,748	(21,898)	(51,973)	(79,424)
4	NET PLANT	$422,387	$405,085	$512,414	$563,253	$568,558	$571,300	$571,418
5	REG. ASSET - DEF. COST/RECOVERY	$44,399	$88,799	$133,198	$151,698	$151,698	$151,698	$151,698
6	LESS: ACCUMULATED AMORTIZATION	8,977	11,357	5,933	2,240	3,016	3,943	5,035
7	NET	$35,423	$77,441	$127,265	$149,458	$148,682	$147,755	$146,663
8	CURRENT ASSETS	438	438	438	650	850	850	850
9	TOTAL ASSETS AND OTHER DEBITS	$458,247	$482,964	$640,116	$713,361	$718,090	$719,905	$718,931
	LIABILITIES AND OTHER CREDITS							
10	LONG-TERM DEBT	$328,125	$328,125	$424,050	$457,175	$450,103	$435,141	$419,960
11	DEFERRED TAXES	15,831	40,617	65,594	87,781	106,145	122,824	137,347
12	EQUITY	114,291	114,221	150,472	168,406	161,842	161,940	161,626
13	TOTAL LIABILITIES AND OTHER CREDITS	$458,247	$482,964	$640,116	$713,361	$718,090	$719,905	$718,931

Exhibit 10

Exhibit ___ (PRC-3)
Docket No. 920807-GP

Exhibit No.___(PRC-4)

NERC Electricity Supply & Demand 1992-2001
Gas-fired Capacity Additions - Florida

Pipe-line(1)	NERC Subrn	Yr	Mo	Util	Unit Name	Sum MW	Unit Type	Fuel Type	Status (2)	Owner-Ship(3)	Notes (4)
FGT	FL	1992	5	VEBM	MUNICIPAL PLANT 5	35	GT	NG	V	U	
FGT	FL	1992	6	LALW	LARSEN 8 CT	72	CT	NG	U	U	
FGT	FL	1992	9	ORLA	INDIAN RIVER CT C	104	GT	NG	U	J	18
FGT	FL	1992	10	ORLA	INDIAN RIVER CT D	104	GT	NG	U	J	18
FGT	FL	1993	1	TAEC	HARDEE POWER STATION	75	CT	NG	C	N	82
FGT	FL	1993	1	TAEC	HARDEE POWER STATION	220	CC	NG	C	N	82
FGT	FL	1993	10	FLPC	PASCO COGEN 1	102	CG	NG	C	N	83
FGT	FL	1993	10	FLPC	LAKE COGEN 1	102	CG	NG	C	N	83
FGT	FL	1993	10	FMPA	CANE ISLAND 1	32	CT	NG	P	U	
	FL	1993	11	FLPC	UNIVERSITY PROJECT P1	40	GT	NG	P	U	
FGT	FL	1994	1	FLPL	MERRITT SQUARE MALL 1	2	CG	NG	OT	N	85
	FL	1994	1	HSTM	G. W. IVEY 8	-2	IC	NG	RT	U	
FGT	FL	1994	1	FLPL	MARTIN CC UNIT 3	416	CC	NG	U	U	
FGT	FL	1994	2	FLPC	ORLANDO COGEN 1	72	CG	NG	C	N	83
FGT	FL	1994	8	FLPC	MULBERRY 1	72	CG	NG	C	N	83
FGT	FL	1994	8	FLPC	EL DORADO 1	104	CG	NG	C	N	83
FGT	FL	1995	1	FLPC	GENERAL PEAT 2	52	OT	NG	C	N	83
FGT	FL	1995	1	FLPC	GENERAL PEAT 3	52	OT	NG	C	N	83
FGT	FL	1995	1	FLPC	GENERAL PEAT 1	52	OT	NG	C	N	83
FGT	FL	1995	1	FMPA	CANE ISLAND 2	120	CC	NG	P	J	123
FGT	FL	1995	1	FLPL	MARTIN CC UNIT 4	416	CC	NG	U	U	
	SOU	1995	3	GUPC	PEAKING	80	GT	GAS	P	U	
FGT	FL	1995	4	FLPC	PANDA KATHLEEN 1	75	CG	NG	C	N	83

Exhibit No.___(PRC-4)

NERC Electricity Supply & Demand 1992-2001
Gas-fired Capacity Additions - Florida

Pipe-line(1)	NERC Subrn	Yr	Mo	Util	Unit Name	Sum MW	Unit Type	Fuel Type	Status (2)	Owner-Ship(3)	Notes (4)
	FL	2000	1	FLPL	MARTIN 5	416	CC	NG	P	U	
	FL	2000	1	FLPL	MARTIN 6	416	CC	NG	P	U	
	FL	2000	3	GUPC	PEAKING	160	GT	GAS	P	U	
	FL	2000	6	TALL	FUEL CELL SUB 17	7	FC	NG	P	U	
	FL	2000	6	GAMW	UNKNOWN HRSG 1	33	ST	NG	P	U	
	FL	2000	6	TALL	FUEL CELL SUB 18	7	FC	NG	P	U	
	FL	2000	6	TALL	SAM PURDOM CC-1	106	CC	NG	P	U	
	FL	2000	6	TALL	FUEL CELL SUB 4	6	FC	NG	P	U	
	FL	2000	11	FLPC	COMBINED CYCLE 4	200	CC	NG	P	U	

(1) FGT=Florida Gas Transmission.
SS=Proposed SunShine Pipeline.

(2) Status
P: Planned for installation, but not utility authorized.
L: Regulatory approval pending, but not under construction.
T: Regulatory approval received, but not under construction.
U: Under construction, less than approx 50% of plant completed.
V: Under construction, greater than approx 50% of plant completed.
RT: Planned for retirement.
C: Signed power contract with utility, financing not obtained, not under construction.
OT: None of the above, see note.

(3) Ownership
J: Utility, Joint Ownership.
U: Utility, Single Ownership.
N: Non-utility ownership.

(4) Notes
18: ORLA 82 MW, FMPA 22 MW.
82: Not a qualifying facility.
83: Under contract.
85: Discussions.
87: Rep. increase to 832/832 MW.
123: FMPA 50%, KUAM 50%.

Exhibit No.___(PRC-4)

NERC Electricity Supply & Demand 1992-2001

Gas-fired Capacity Additions - Florida

Pipe-line(1)	NERC Subrn	Yr	Mo	Util	Unit Name	Sum MW	Unit Type	Fuel Type	Status (2)	Owner-Ship(3)	Notes (4)
	FL	1995	7	TAEC	POLK UNIT 1:CT-1A	150	CT	NG	L	U	
	FL	1996	1	FLPC	CFR-BIOGEN 1	74	CG	NG	C	N	83
	FL	1996	1	SECI	UNKNOWN 1	75	GT	NG	P	U	
	SOU	1996	3	GUPC	PEAKING	80	GT	GAS	P	U	
	FL	1998	1	HSTM	G. W. IVEY 9-10	-4	IC	NG	RT	U	
	FL	1998	1	GAMW	J. R. KELLY 7	-20	ST	NG	RT	U	
	FL	1998	6	GAMW	UNKNOWN GT 1	35	GT	NG	P	U	
FGT	FL	1998	6	TALL	A. B. HOPKINS GT-3	66	GT	NG	P	U	
SS?	FL	1998	11	FLPC	COMBINED CYCLE 1	200	CC	NG	P	U	
	FL	1999	1	SECI	UNKNOWN 2	220	CC	NG	P	U	
	FL	1999	1	SECI	UNKNOWN 3	220	CC	NG	P	U	
	FL	1999	1	TAEC	POLK UNIT 2:CT-2A	67	CT	NG	P	U	
	SOU	1999	3	GUPC	PEAKING	80	GT	GAS	P	U	
	FL	1999	6	GAMW	UNKNOWN GT 2	35	GT	NG	P	U	
SS?	FL	1999	11	FLPC	COMBINED CYCLE 2	200	CC	NG	P	U	
	FL	1999	11	FLPC	COMBINED CYCLE 3	200	CC	NG	P	U	
	FL	2000	1	GAMW	J. R. KELLY 8	-41	ST	NG	RT	U	
	FL	2000	1	HSTM	G. W. IVEY 11-12	-6	IC	NG	RT	U	
	FL	2000	1	HSTM	G. W. IVEY 2-3	-4	IC	NG	RT	U	
	FL	2000	1	GAMW	J. R. KELLY 6	-19	ST	NG	RT	U	
	FL	2000	1	TAEC	POLK UNIT 2:CT-2B	67	CT	NG	P	U	
	FL	2000	1	LALW	UNKNOWN	72	CC	NG	P	U	

Coastal
The Energy People

March 8, 1993

Mr. Leonard A. Bluhm
Cypress Energy Partners, L.P.
1852 W Hwy 70
Okeechobee, Florida 34974

Re: ANR Southern Pipeline Company Precedent Agreements

Dear Mr. Bluhm:

ANR Southern Pipeline Company ("ANRS") and Cypress Energy Partners, L.P. ("Cypress") have been engaged in discussions regarding ANRS' effort to develop and construct new natural gas pipeline systems that would substantially increase natural gas transmission capacity to gas consuming markets in the State of Florida. ANRS has advised Cypress that it has recently formed two general partnerships with separate special purpose subsidiaries of Florida Power Corporation for this purpose. SunShine Pipeline Partners, a Florida general partnership between ANRS and Power Energy Services Corporation, plans to construct, own and operate an intrastate natural gas pipeline known as SunShine Pipeline Company ("SunShine"). SunShine Interstate Pipeline Partners, a Texas general partnership between ANRS and Power Interstate Energy Services Corporation, plans to construct, own and operate an interstate pipeline known as SunShine Interstate Transmission Company ("SITCO"). The purpose of this letter is to express the undersigned parties' intentions regarding SunShine and SITCO.

ANR has presented Precedent Agreements to Cypress providing for firm transportation service across both the SunShine and SITCO systems for a maximum daily quantity ("MDQ") of 80,000 MMBtus in 1998 and 80,000 MMBtus in 1999. SunShine has advised Cypress that upon execution of its Precedent Agreement, Cypress would appear on an exhibit supporting SunShine Pipeline Partners' Application for Determination of Need before the Florida Public Service Commission ("FPSC") which lists SunShine's contracted shippers, volume, location and in-service date. Cypress has expressed its intention to purchase firm natural gas transportation service from SunShine and SITCO, but is unable to resolve all contractual issues to commit to tender the full 160,000 MMBtus prior to the date that the aforesaid application before the FPSC will be filed. The Parties believe that the matters which preclude Cypress' execution of the Precedent Agreements can be resolved within sixty (60) days of the date that SunShine files its application.

Accordingly, the parties agree that they will, within sixty (60) days from the date herein, use their best efforts to successfully resolve the matters which preclude Cypress' ability to execute the Precedent Agreements submitted to it by SunShine and SITCO. In the event such matters are successfully resolved within such time period, Cypress will so notify ANR Southern and agrees to execute the Precedent Agreements providing an MDQ of 80,000 MMBtus in 1998 and 80,000 MMBtus in 1999. In the event that Cypress is unable to successfully resolve the matters which preclude its ability to execute said Precedent Agreements within sixty (60) days of the date herein, then this agreement will expire and the parties agree to renegotiate a mutually acceptable MDQ level.

If you are in agreement with the foregoing, please indicate your acceptance by executing the duplicate originals in the space provided below and returning one copy of the undersigned for our files.

Very truly yours,

ANR SOUTHERN PIPELINE COMPANY

By R. Allan Bradley
R. Allan Bradley
Vice President

Accepted and Agreed to
this 8 day of March 1993.

CYPRESS ENERGY PARTNERS, L.P.

By Leonard A. Bluhm

jps\ltr24

Florida Power Corporation Pipeline Ownership
Proposed Regulatory Treatment
February 23, 1993

Objectives and Rationale

1) FPC's objective is to minimize the cost of natural gas transportation to our electric customers. It is expected that FPC's commitment for 210,000 MMBTU/day of gas transportation capacity will represent approximately one-half of the total capacity of the new gas pipeline. The purpose of FPC's ownership position in the proposed pipeline is to protect and further FPC's interests as a pipeline customer. As an owner, FPC will have influence over the management of the pipeline and will have an opportunity to gain access to useful gas market information which will benefit FPC's customers.

2) A regulatory treatment which sets FPC's rate of return on its pipeline investment will forestall any potential concerns regarding conflict of interest or self-dealing due to FPC being both a customer and a part owner of the pipeline.

3) The proposed regulatory treatment offers benefits to both customers and shareholders by reducing the long-term cost of gas transportation for customers while at the same time providing shareholders with a stable rate of return.

Basis for Proposed Regulatory Treatment

1) FPC proposes to take a one-third ownership position in both the interstate pipeline and the intrastate pipeline, resulting in a total equity investment of approximately $45 million. The company will use the equity method to account for its ownership position. The assets and operating revenues and expenses of the pipeline will reside in unconsolidated partnerships which will be separately regulated by the PSC and FERC. As a result, the proposed regulatory treatment pertains only to FPC's equity investment in the pipeline.

2) FPC's pipeline investment closely parallels the investment in Electric Fuel's assets used to deliver coal to FPC's coal units at Crystal River. For example, EFC is a one-third owner of International Marine Terminals and the return on equity for this investment is regulated using a methodology comparable to what is being proposed here. The regulatory treatment of EFC's investment in these assets has proven to be successful and to serve the interests of customers well. Based on this precedent, FPC's pipeline investment should be afforded similar treatment.

3) The regulatory return on equity for the pipeline is expected to be higher than the corresponding return on equity for FPC's electric business due to a recognition of the somewhat higher risk of the pipeline business. This relationship creates an opportunity for a sharing of the benefits of this investment between customers and shareholders.

4) All costs associated with the transportation and delivery of fuel are ordinarily recovered through the fuel adjustment. Therefore, since the proposed treatment represents only an adjustment to the return on equity for this investment, it is appropriate that the adjustment be effected through the fuel adjustment as well.

Implementation of Proposed Regulatory Treatment

The return on equity experienced by the pipeline may at times be higher or lower than the return on equity allowed to FPC under the proposed regulatory treatment. This difference would result in a true-up of the return on equity to the allowed return. The true-up amount would in turn appear to electric customers as an adjustment to the delivered cost of natural gas. The potential impact of the resulting true-up calculation on fuel cost assuming that FPC makes an equity investment of $45 million in the pipeline is illustrated as follows:

	$ Millions			
Pipeline ROE%	FPC Share of Pipeline Net Income	Allowed Net Income At 13% ROE	Over/ (Under) Net Income	Fuel Cost Impact $/MMBTU
11%	$ 4.95	$ 5.85	($ 0.9)	($ 0.019)
12%	5.40	5.85	(0.45)	(0.009)
13%	5.85	5.85	0.0	0.0
14%	6.30	5.85	0.45	0.009
15%	6.75	5.85	0.9	0.019

This schedule indicates the true-up amount required for a given period resulting from a pipeline return on equity ranging from 11% to 15%, relative to an assumed allowed return on equity for FPC of 13%. For example, in 1999 FPC is projected to use 210,000 MMBTU/day of natural gas at a delivered cost of $3.61/MMBTU. As shown above, the true-up required for a realized pipeline return on equity of 11% or 15% would be, respectively, a charge or credit of $0.019/MMBTU, corresponding to a 0.5% adjustment to the delivered cost of natural gas for FPC.

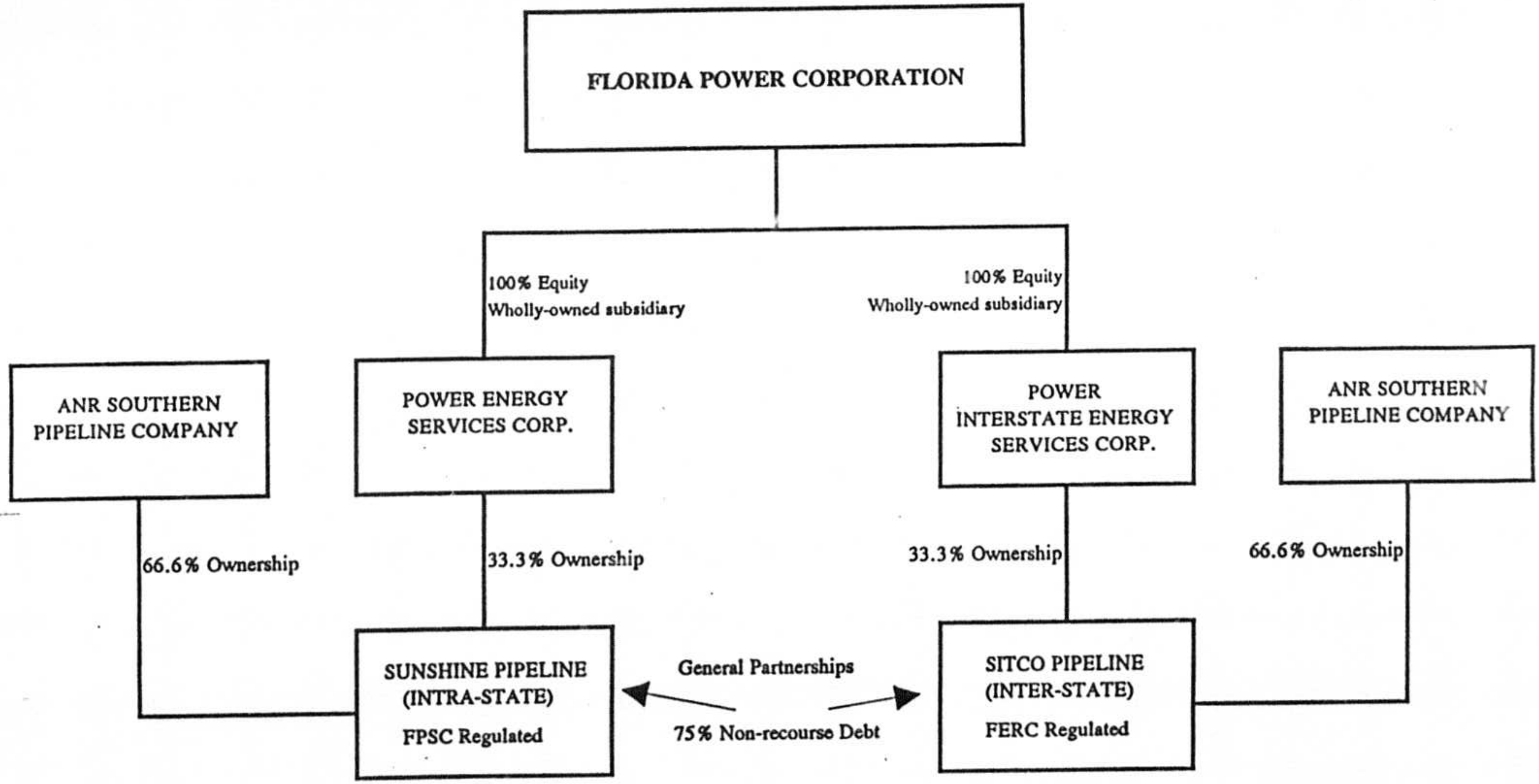
Fuel Adjustment Recovery

In order to set FPC's return on equity for its pipeline equity investment at a given level, some means of truing-up the actual return to the allowed return is needed. It is proposed that the fuel adjustment is the proper and appropriate mechanism to achieve this result for the following reasons:

1) As a result of the levelized rate methodology used by the pipeline, the realized return on equity of the pipeline will not be constant during its life. The fuel adjustment can accommodate changes in the pipeline's return on equity and insure achievement of the authorized return on equity for FPC's investment.

2) Due to the fact that these costs are associated with fuel transportation, the fuel adjustment will achieve a proper allocation of these costs and credits to customer classes.

PROPOSED OWNERSHIP AND CAPITAL STRUCTURE OF PIPELINE



SUNSHINE PIPELINE

On a 100% Basis,
Capital ($Mils):

Debt	352
Equity	118
Total	470

SITCO PIPELINE

On a 100% Basis,
Capital ($Mils):

Debt	122
Equity	41
Total	163

Exhibit ___ (PRC-6)
Docket No. 920807-GP