BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

DOCKET NO. 090172-EI
FLORIDA POWER & LIGHT COMPANY

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

REBUTTAL TESTIMONY & EXHIBITS OF

JONATHAN D. OGUR

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JULY 2, 2009

INTRODUCTION

Q. Please state your name and business address.

A. My name is Jonathan D. Ogur. My business address is Brown, Williams, Moorhead & Quinn, Inc., Energy Consultants, 1155 15th Street, N.W., Suite 400, Washington, D.C., 20005.

Q. Have you previously submitted testimony in this proceeding?

A. Yes. On May 29, 2009, I filed supplemental testimony in this proceeding on behalf of Florida Power & Light Company (FPL).

Q. Are you sponsoring any rebuttal exhibits in this case?

A. Yes. I am sponsoring the following rebuttal exhibit:

- JDO-3 Prepared Rebuttal Testimony of Benjamin Schlesinger, *Pacific Gas Transmission Company*, Docket No. RP94-149-000 *et al.*

Q. What is the purpose of your rebuttal testimony?

A. The purpose of my rebuttal testimony is to respond to the direct testimony of

Benjamin Schlesinger and Michael T. Langston, who submitted testimony in this proceeding on behalf of Florida Gas Transmission Company, LLC (FGT).

Q. Please summarize the main conclusions of your rebuttal testimony.

A. Dr. Schlesinger and Mr. Langston incorrectly assume that FERC regulation has eliminated competitive problems in gas transmission markets. The markets for long-term firm gas transmission in Florida are highly concentrated and characterized by low levels of excess capacity. FERC regulation mitigates, but does not eliminate, the potential exercise of market power. Incumbent pipelines, such as FGT, possess market power, and may be negotiating rates that, although less than the maximum cost-of-service rates, are greater than the competitive level. Entry by a new pipeline, such as the Florida EnergySecure Line (EnergySecure Line), will promote competition and put downward pressure on negotiated rates.

Q. Which parts of the FGT witnesses' testimony do you address?

A. I address the following issues:

(1) Dr. Schlesinger argues that Federal Energy Regulatory Commission (FERC) rules, starting with Order No. 636, and policies, including open access and capacity release, have eliminated market power problems in gas transmission markets. (FGT witness Schlesinger, pages 19-20)

(2) As a result, he further argues that a competition analysis using the Herfindahl-Hirshman Index (HHI) to measure market concentration is meaningless.

(3) In addition, Dr. Schlesinger suggests that, if the EnergySecure Line supplies only FPL's generation, it will not promote competition in Florida. (FGT witness Schlesinger, page 20)

(4) Mr. Langston argues that, because gas pipelines are regulated, there is no competitive benefit from the entry of a new pipeline. (FGT witness Langston's Direct Testimony, page 18)

(5) Mr. Langston also criticizes FPL for not structuring the EnergySecure Line as an open access pipeline like interstate pipelines under FERC regulation and similar to intrastate pipelines in California under California Public Utilities Commission (CPUC) regulation. (FGT witness Langston's Direct Testimony, pages 42-43)

(6) Finally, Mr. Langston claims that, if FPL is allowed to include the EnergySecure Line in its electric rate base, FPL will have an unfair competitive advantage over existing pipeline capacity providers in future expansions. (FGT witness Langston's Direct Testimony, page 43)

Q. In general, how would you characterize the position taken by the two FGT witnesses on market power in gas transmission markets?

A. Dr. Schlesinger and Mr. Langston have adopted an overly simplistic and extreme position, which assumes that the FERC has eliminated market power problems in gas transmission markets. Their position is at odds with that of the FERC, which, as described more fully below, recognizes that market power remains in these markets.

Q. Given that there is still market power in gas transmission markets, do you agree with Dr. Schlesinger that the HHI is meaningless?

A. No. Competition analysis based in part on the HHI has an important role to play in the assessment of market power in gas transmission markets. I will illustrate the use of this analysis in Florida's long-term firm gas transmission markets later in my rebuttal testimony.

Q. Do you agree with Dr. Schlesinger's suggestion that, if the EnergySecure Line supplies only FPL's generation, it will not promote competition in Florida?

A. No. FPL plans initially to use at least 400 million cubic feet per day (MMcf/d) of the EnergySecure Line's 600 MMcf/d capacity to serve FPL generation expansions. As I showed in my supplemental testimony, the gas transmission markets serving the FPL system and the individual FPL generation expansions are highly concentrated. These high concentration levels together with low levels of excess capacity in Florida suggest that the incumbent pipelines, FGT and Gulfstream, possess market power. Entry of a new pipeline, the EnergySecure Line, into the markets serving FPL generation will reduce concentration and promote competition. As FPL gas transportation needs increase, the EnergySecure Line has the potential to expand from its initial capacity of 600 MMcf/d to 1.25 Bcf/d, further reducing concentration and promoting competition. In addition, the EnergySecure Line will promote economic efficiency in the transmission markets serving FPL generation.

Q. Will the EnergySecure Line also promote competition in the broader market for transmission to the State of Florida as a whole?

A. Yes, while the primary purpose of the EnergySecure Line is to supply FPL's current and future generation expansions, FPL plans initially to make up to 200 MMcf/d available to unaffiliated shippers. As a result, the EnergySecure Line will have a significant pro-competitive effect in the broader transmission market serving the State of Florida as a whole. In addition, the EnergySecure Line will promote economic efficiency in that market.

Q. Do you agree with Mr. Langston that there is no competitive benefit from the entry of a new pipeline?

A. No. Entry is a powerful force that promotes competition and puts downward pressure on prices in gas transmission and delivered gas markets. In fact, FGT's Dr. Schlesinger presented evidence of the competitive benefits of pipeline entry and capacity expansion an earlier proceeding. (Exhibit JDO-3, Schlesinger Rebuttal Testimony, *Pacific Gas Transmission Company*, Docket No. RP94-149-000 *et al.*) He found that California consumers benefited from decreased gas prices as the result of the Kern River pipeline entry and the PGT Expansion. (Exhibit JDO-3, page 10) Dr. Schlesinger estimated the PGT Expansion benefits at $382 million per year. (Exhibit JDO-3, page 16) He concluded that these benefits resulted from increased competition in the California delivered gas market caused by the entry of lower cost gas from Alberta. (Exhibit JDO-3, page 18) Dr. Schlesinger also observed that incumbent pipelines decreased prices in anticipation of the Kern River pipeline entry. (Exhibit JDO-3, page 23) Further, he concluded that the competitive benefits accrued to all California gas customers whose prices were tied to market levels. (Exhibit JDO-3, page 34) Finally, he found that the reduction in gas prices at the California border caused a reduction in Southwest Basin and Pacific Northwest prices. (Exhibit JDO-3, pages 22 and 37)

Q. Would the competitive benefits of entry observed in California gas markets occur generally in gas markets?

A. Yes. Entry generally produces downward pressure on prices. In fact, the anticipation of entry in the near future often leads to downward pressure on current prices.

Q. Are the competitive benefits of entry in the California gas markets as described by Dr. Schlesinger likely to apply to Florida gas markets?

A. Yes. To some extent the competitive benefits of entry are already observable in Florida. As described in the rebuttal testimony of FPL witness Forrest, FGT's unsolicited proposals to FPL and the corresponding price reductions reflect downward price pressure resulting from the potential entry of the EnergySecure Line. After actual entry, the EnergySecure Line is likely to increase the downward pressure on gas transmission and delivered gas prices, to the benefit of FPL customers and Florida consumers generally.

Q. What is your opinion on Mr. Langston's criticism that FPL has not structured the EnergySecure Line like an open access interstate pipeline under FERC regulation?

A. Mr. Langston's criticism fails to recognize that the primary purpose of the EnergySecure Line is to supply gas to FPL's current and future generation expansions. Initially, FPL's generation will use at least 400 MMcf/d of the pipeline's 600 MMcf/d base-level capacity. Usage is projected to grow over time to require all of the base-level capacity as well as the capacity expansions that can be achieved through added compression. Until all of the base-level capacity is needed for FPL's generation, however, FPL intends to help reduce the pipeline's cost to its electric customers by making the excess capacity available to unaffiliated shippers. FPL will make up to 200 MMcf/d available to unaffiliated shippers on a basis that is not unreasonably preferential, prejudicial, or unduly discriminatory either directly or through release of its capacity on other pipelines. FPL will follow FERC requirements for any capacity releases to ensure that the process is open and non-discriminatory. In the case of any sales, FPL will post the capacity in an open and transparent manner and seek bids in order to ensure non-discriminatory access to the capacity and award the capacity to the highest bidders. FPL also will file tariffs governing these sales with the Florida Public Service Commission (FPSC).

Q. Do Mr. Langston's and Dr. Schlesinger's references to the regulation of California intrastate pipelines apply to Florida natural gas transmission and delivered natural gas markets?

A. No. Mr. Langston's and Dr. Schlesinger's references to the regulation of California intrastate pipelines ignore fundamental differences between the Florida and California natural gas transmission and delivered natural gas markets. For example, interstate pipelines deliver most gas only to the California border, where intrastate pipelines then provide the further transmission service required to deliver gas to the city gate or to the end user. By contrast, interstate pipelines, such as FGT and

Gulfstream, deliver gas to end users located within the state of Florida. Also, while electric utilities in California have largely unbundled their generation, electric utilities in Florida retain their generation and hence are end users of gas on a scale that has no counterpart in California. In fact, the vast majority of the total gas consumed in Florida is consumed by electric generators, whereas gas consumption in California is more evenly divided among residential users, small business, electric generators, and large industrial users. In sum, California gas transmission and delivered gas markets are fundamentally different from Florida markets.

Q. Do you agree with Mr. Langston that allowing FPL to include the EnergySecure Line in its electric rate base will give FPL an unfair competitive advantage in future expansions?

A. No. Mr. Langston's claim (FGT witness Langston Direct Testimony, page 43) appears to be based on either a misunderstanding of the FPSC's regulatory procedures or an incorrect assumption of regulatory failure by the FPSC. It is my understanding that the FPSC would oversee future expansions, either by conducting proceedings before the expansion, or through prudency reviews after the expansion. In either case, the FPSC would evaluate evidence to ensure that the most cost-effective alternative was selected for the expansions.

Similarly, the fact that FPL will be the primary shipper on its own pipeline would not create a competitive advantage. In this case, FPL generation will own, and be the largest shipper on, the EnergySecure Line, a vertical relationship. As a general proposition, such vertical relationships do not create competitive advantages. As I will illustrate in the next section of my rebuttal testimony, competition issues are generally analyzed by considering horizontal relationships, e.g. in markets for gas transmission, rather than vertical relationships.

MARKET POWER IN GAS TRANSMISSION MARKETS

Q. Does the FERC agree with Dr. Schlesinger and Mr. Langston that it has eliminated competitive problems in gas transmission markets?

A. No.

Q. Would you briefly summarize the FERC's position on market power in gas transmission markets?

A. The FERC has recognized that market power is a continuing concern in gas transmission markets.

> [W]hile the data indicates that the short-term secondary market is competitive in general; we have not made a finding that every segment of every pipeline is competitive... [T]he Commission's selective discounting policy permits pipelines to restrict a shipper's discount to specific points, so that the shipper must pay the pipeline's maximum rate if it releases the capacity to a replacement shipper who uses different points where the pipeline faces less competition [fn]. ... Retaining the recourse rate *helps* [emphasis added] protect against the pipeline's abuse of market power in the sale of capacity on any such segments of its system.

(*Promotion of a More Efficient Capacity Release Market*, Docket No. RM081-000, Order No. 712 (June 19, 2008) 123 FERC ¶ 61,286 at P. 88) (Order No. 712)

In short, some transmission markets (e.g., segments) are more competitive than others, and the extent of discounting reflects the degree of competition in those markets. A recourse rate mitigates, but does not eliminate, the exercise of market power.

Q. Why does FERC regulation not eliminate the exercise of market power in gas transmission markets?

A. The FERC seeks to achieve two goals, promoting efficiency and protecting against the exercise of market power, and recognizes that there is a tradeoff between these goals.

> The Commission's objective in designing rates is to establish a ratesetting framework that increases efficiency in the marketplace, while protecting against the potential exercise of market power. No regulated rate can perfectly emulate the prices found in a competitive marketplace nor protect perfectly against the exercise of market power. …Thus, price regulation often permits some exercise of market power and involves tradeoffs between pricing efficiency and the regulatory control over market power.

(*Regulation of Short-Term Natural Gas Transportation Services, and Regulation of Interstate Natural Gas Transportation Services*, Docket Nos. RM98-10-000 and RM98-12-000; Order No. 637 (February 9, 2000) 90 FERC 61,109 at 31,269)

Q. How can pipelines exercise market power if their rates are subject to a maximum cost of service rate?

A. Under FERC regulation, a pipeline can discount selectively, offering larger discounts where competition is stronger. (Order No. 712 at P. 88) The efficiency-enhancing role of selective discounting to meet varying degrees of competition and attract or retain business has long been recognized by the FERC. (see *Policy Statement Providing Guidance with Respect to the Designing of Rates*, 47 FERC 61,295 (May 30, 1989) at 62,053) Although these discounted rates are below the maximum cost-of-service rate, they may nevertheless exceed the competitive price where competition is weaker. A pipeline exercises market power when it profitably maintains price above the competitive level for a significant period of time. (FPL witness Ogur Supplemental Testimony, page 6)

Q. Does a recourse rate eliminate the possibility of a pipeline exercising market power?

A. No, a recourse rate mitigates the exercise of market power by preventing a pipeline from demanding prices above the maximum cost-of-service level or withholding service. (*Alternatives to Traditional Cost-of-Service Ratemaking for Natural Gas Pipelines*, Docket No. RM95-6-000, *Regulation of Negotiated Transportation Services of Natural Gas Pipelines*, Docket No. RM96-7-000, (January 31, 1996) 74 FERC ¶ 61,076, at 61,231) (Gas Policy Statement) However, a recourse rate does not prevent the exercise of market power by a pipeline charging a rate that is less than the maximum cost-of-service rate, but greater than the competitive rate.

Q. Does FGT sell capacity at a rate that is less than its maximum cost of service rate?

A. Yes. FGT has entered into long-term contracts with customers for its Phase VIII expansion capacity at a negotiated rate that is fixed and is less than the maximum cost of service recourse rate. (FGT witness Langston Direct Testimony, page 39)

Q. Is it possible that FGT's negotiated rate is greater than the competitive level?

A. Yes. Depending on the strength of competition in Florida gas transmission markets, FGT's negotiated rate may exceed the competitive level.

COMPETITION ANALYSIS

Q. Given that, contrary to the simplistic assumption of Dr. Schlesinger and Mr. Langston, some competitive problems remain in gas transmission markets, what analytical framework would you use to assess those problems?

A. I would use the FERC's competition analysis, which consists of the following three steps:

(1) define the relevant markets;

(2) measure a firm's market share and market concentration; and

(3) evaluate other relevant factors.

(Gas Policy Statement at 61,240)

Using FERC's competition analysis, I would assess whether FGT's negotiated rate exceeds the competitive level and, more generally, the strength of competition in Florida gas transmission markets.

Q. How would you begin to define the relevant markets?

A. I would begin by identifying good alternatives. The concept of a good alternative is central to FERC's competition analysis. (Gas Policy Statement at 61,231) The first step in the analysis, market definition, identifies the specific products or services and the suppliers of those products or services that would provide good alternatives if a pipeline attempted to exercise market power.

Q. What is a good alternative?

A. A good alternative is defined as "an alternative that is available soon enough, has a price that is low enough, and has a quality high enough to permit customers to substitute the alternative for the service." (Gas Policy Statement at 61,231) The service of the pipeline under analysis and good alternatives are referred to as the product market. Each alternative in the product market must be an adequate substitute for the service of the pipeline under analysis in terms of quality, price and availability.

Q. How soon must an alternative be available to meet the availability requirement?

A. The specific time period depends on the product in question. (Gas Policy Statement at 61,231) For example, if the product is long-term firm transportation, substitute capacity would need to be available simultaneously to offer a viable alternative to customers. For example, substitute capacity would have to be available at the time when FGT is negotiating with shippers for its Phase VIII expansion capacity to meet the availability requirement of a good alternative to FGT's long-term firm service on that capacity.

Q. How low must the alternative's price be to meet the price requirement?

A. In general, the alternative's price must be within 10 percent of the price of the pipeline under analysis. (Gas Policy Statement at 61,232)

Q. How high must the alternative's quality of service be to meet the quality requirement?

A. The alternative's quality of service must be at least as high as that of the pipeline under analysis. For example, to show that an interruptible service is a good alternative to the firm service of the pipeline under analysis, there must be an adequate amount of unsubscribed capacity during peak periods to make the risk of interruption comparable to that of the firm service. (Gas Policy Statement at 61,232)

Q. What guidance does the FERC provide for the evaluation of alternatives?

A. The FERC states that a narrow definition of the product market, for example, peak-period, firm transportation or off-peak, interruptible transportation, will better enable FERC to critically evaluate proposed alternatives to the pipeline under analysis. (Gas Policy Statement at 61,231)

Q. In the light of the FERC's guidance, how would you define the product market in this proceeding?

A. I would define the product market as long-term firm pipeline transmission capacity in Florida. The EnergySecure Line will supply gas to expansions of FPL's base load capacity, which requires a "consistent supply source to support fuel requirements." (Sexton Testimony at 34-35) I would interpret this requirement as a need for both transmission capacity and gas on a long-term firm basis.

Q. Is the market for long-term firm transmission significant in Florida?

A. Yes. Electric generators use more than 85 percent of the gas consumed in Florida. (FPL witness Sexton Direct Testimony, page 10) A substantial proportion of the generation is base load and thus requires long-term firm transmission.

Q. What additional evidence supports the significance of the long-term firm transmission market in Florida?

A. Customers for FGT's Phase VIII expansion capacity have entered into long-term firm contracts with FGT. (FGT witness Langston Direct Testimony, page 39)

Q. Are capacity release, storage, and LNG imports likely to be good alternatives to long-term firm pipeline capacity and thus included in this product market?

A. No. Capacity release, storage, and LNG imports are not likely to be good alternatives to long-term firm pipeline capacity.

Q. Why is capacity release not likely to be a good alternative to long-term firm pipeline capacity?

A. Capacity release is unlikely to meet the availability and price requirements of a good alternative to long-term firm pipeline capacity and may not meet the quality requirement. Because of the high levels of pipeline capacity utilization in Florida, capacity release cannot provide significant amounts of long-term firm capacity. Pipeline capacity into Florida is utilized at 70 percent of design capacity on an annual basis, 80 percent of design capacity during the summer and in excess of 96 percent of design capacity on select days. (FPL witness Sexton's Direct Testimony, pages 10-11) Given these high utilization levels, it is unlikely that firm rights holders would release a significant amount of capacity on a long-term firm basis in response to a ten percent price increase. Even if some small amount of capacity were released, it might be subject to recall and would thus fail to meet the quality requirement of a good alternative.

Q. Have the FERC and courts recognized that capacity release is not available on the same basis as pipeline capacity?

A. Yes. Both the FERC and the United States Court of Appeals for the District of Columbia Circuit (D.C. Circuit) have recognized that the capacity of the pipeline is on hand and ready to be sold, whereas the capacity held by releasing shippers is not necessarily available, since much of it may be needed to serve its native loads. (Order No. 712 at P. 94)

Q. Why is storage not likely to be a good alternative to long-term firm pipeline capacity?

A. Like capacity release, storage is unlikely to meet the availability requirement of a good alternative. At present, there is no storage within Florida. Any new storage would have to be constructed above ground and could not supply base load generators on a long-term firm basis. (FPL witness Sexton's Direct Testimony, pages 34-35) Storage located outside of Florida would be unable to obtain additional transmission capacity to deliver gas to Florida customers on a long-term firm basis because pipeline capacity into Florida is already fully subscribed.

Q. Why are LNG imports not likely to be a good alternative to long-term firm pipeline capacity?

A. Like capacity release and storage, LNG imports are unlikely to meet the availability requirement of a good alternative. Like storage located outside of Florida, LNG imports would be unable to obtain additional transmission capacity on a long-term firm basis to transport the LNG from its coastal locations to the destinations where users are located. (FPL witness Sexton's Direct Testimony, page 34)

CONCLUSIONS

Q. Please summarize your conclusions.

A. Dr. Schlesinger and Mr. Langston incorrectly assume that FERC regulation has eliminated competitive problems in gas transmission markets. The markets for long-term firm gas transmission in Florida are highly concentrated and characterized by low levels of excess capacity. (FPL witness Ogur's Supplemental Testimony, pages 12-14). FERC regulation mitigates, but does not eliminate, the potential exercise of market power. Incumbent pipelines, such as FGT, possess market power, and may be negotiating rates that, although less than the maximum cost-of-service rates, are greater than the competitive level. Entry by a new pipeline, such as the EnergySecure Line will promote competition and put downward pressure on negotiated rates.

Q. Does this conclude your rebuttal testimony?

A. Yes.

United States of America
Federal Energy Regulatory Commission

Pacific Gas Transmission Company	))	Docket No. RP94-149-000, et al.

Prepared Rebuttal Testimony of
Benjamin Schlesinger, Ph.D.

I. Introduction and Background

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

A. My name is Benjamin Schlesinger. I am president of Benjamin Schlesinger and Associates, Inc. (hereinafter "BSA"), which is located at The Bethesda Gateway, 7201 Wisconsin Avenue, Suite 740, Bethesda, Maryland, 20814.

Q. On whose behalf are you appearing in these proceedings?

A. I am appearing on behalf of Pacific Gas Transmission Company (PGT).

Q. Please describe Benjamin Schlesinger and Associates, Inc.

A. BSA is a management consulting firm, which I founded in 1984, specializing in analysis of all strategic aspects of the natural gas industry, including commercial, regulatory, economic, and business structural issues. We also have prepared a number of special gas industry analyses for the American Gas Association (AGA) and other major industry

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organizations.

Q. Please describe your professional qualifications.

A. I have spent 24 years in conducting, performing and leading energy analysis, and related economic and environmental projects. My work has focused on the natural gas industry, especially on its regulation and commercial evolution over the past decade and a half, including price decontrol, contracting concerns, the evolution and growth of spot trading and open access transportation, and the resurgence of growth in the gas industry, both in sales and facility investments, including in all of its traditional and nontraditional markets, e.g., new power generation and automotive uses. My curriculum vitae appears in Exhibit No.____(BSA-2).

Briefly, I hold undergraduate degrees in arts and engineering from Dartmouth College and an M.S. and Ph.D. from Stanford University in Industrial Engineering. I worked as a project engineer with the Bechtel Corporation in San Francisco during the early 1970s, where I conducted cost-benefit and environmental analyses of energy and transportation projects. Following two years with the Federal Government (U.S. Geological Survey and Energy Research and Development Administration), I joined the American Gas Association in 1977, and spent four years as vice president for policy evaluation and analysis. At AGA, I directed the Association's gas supply and demand analyses, and my group prepared more than 80 special reports and studies dealing with gas prices, regulation, markets, and related industry topics. I began my consulting career in 1982 with Booz-Allen & Hamilton, Inc. in Bethesda, Maryland, where I was a principal leading the firm's efforts in the natural gas area. In 1984 I formed my own firm.

Q. Have you testified before?

A. Yes. I have testified on major gas industry and business issues before the Federal Energy Regulatory Commission (FERC), various U.S. House and Senate Energy Committees, the U.S. Department of Energy, and utility regulatory and other panels in Alaska, Arizona, California, Connecticut, Florida, Louisiana, Maryland, Massachusetts, Mississippi, New Mexico, Ohio, Ontario and Texas. A list of my expert witness testimony is contained in Exhibit No. ____ (BSA-3).

Q. Have you testified with respect to rolled-in versus incremental cost allocation or gas-on-gas competition benefits before?

A. Yes. My testimony in 1992 before the California Public Utilities Commission en banc proceeding focused on competition and pricing in spot and long-term gas markets. My testimony in 1993 before the Ontario Energy Board dealt with the use and interpretation of various gas market price indices.

Q. What is the purpose of your testimony in these proceedings?

A. I will rebut some faulty and unbalanced reasoning contained in the prepared testimony of several witnesses who are opposing the proposal that PGT has put before the Commission for rolled-in rate treatment for its 1993 Expansion. In particular, four such witnesses -- CPUC Witness Natalie Walsh, Cascade Witness Jon T. Stoltz, Washington Natural Gas Witness Jerome J. Sullivan, and El Paso Natural Gas Witness Robert Weisenmiller -- attempt to dismiss or discount PGT's evidence that gas customers in the Pacific Region (California, in particular) have enjoyed clear and significant gas cost benefits as a result of the gas-on-gas competition induced by the November 1993 PGT Expansion. Gas customers in these regions have enjoyed a clear and demonstrable benefit from PGT's Expansion in excess of $398 million per year. This estimate is based on reported price and volume data, rather than on any computer simulation model.

II. Measuring the Gas Competition Benefits of Gas Pipeline Expansions

Q. Do gas users benefit when pipeline capacity is added?

A. Yes, in several ways. First, added capacity means there are more physical facilities in place to serve the same geographical market as before. This, in turn, means increased system flexibility and reliability for all users, including users who pre-date the expansion. Even if pre-expansion shippers are able to demonstrate their service was reliable on the old pipeline, past performance is no sure indication of future reliability. Growth in gas markets and evolving production trends would have eventually diminished service reliability without the new capacity addition.

Second, for pipeline expansions adding capacity from lower-cost producing areas, one of their most important benefits is the lower consumer gas costs caused by the increase in gas-on-gas competition enabled by the addition of pipeline capacity. From basic economic principles, it is clear that increased availability of lower-cost supplies will be followed by periods of competitive pricing which, in turn, will force prices to be lower than they would otherwise have been. One example of this effect has been the opening of Rocky Mountain gas supplies to California markets (through the Kern River pipeline). This latter form of benefit is quite real, and it has clearly happened in the case of the PGT Expansion.

Q. How can the foregoing benefit of lower consumer gas costs be measured?

A. Simply put, the gas-on-gas competitive benefit is measurable by comparing gas costs paid by purchasers in the market region before and after the expansion, against a standard gas price in the market's major supply region. Since gas market prices are volatile, the use of a standard gas price in the major supply region is an important way to exclude many of the factors that affect gas prices in a more global sense, e.g., seasonality, overall market growth, oil price competition, and other general price determinants. The market area gas price, therefore, is expressed as a basis difference from the standard, i.e., the difference between the market area price and the relevant supply area price. Then, a determination of whether or not the pipeline had an effect is made by comparing how that basis difference looks, i.e., how great it is, after the expansion versus before the expansion. Benefit is demonstrated if the basis falls, i.e., market price declines relative to supply price after the expansion is placed into service.

III. California Gas Market Competition

Benefits of the PGT Expansion

Q. Did the PGT Expansion benefit California gas customers?

A. Yes, it did so significantly by reducing gas costs to California gas users to lower levels than would otherwise have been the case.

Q. Please explain.

A. The major gas buyers in California include local distribution companies (LDCs) such as Pacific Gas & Electric Company and Southern California Gas, utility electricity generators, non-utility generators, as well as many industrial and commercial customers. The price that major buyers pay for physical gas supplies at the California border is reported by various trade press, including Inside FERC's Gas Market Report (GMR), Gas Daily, Natural Gas Week (NGW), and Natural Gas Intelligence (NGI). The physical market prices of gas in the region's representative producing basin are also reported by the same trade press for the same periods of time. Thus, one appropriate measure of gas cost benefits is the difference between GMR's price index for California and GMR's price index for the Permian Basin. Also appropriate would be the difference between Gas Daily's California price and Gas Daily's Permian price. By using the same publication's reported gas prices, we eliminate methodological differences with respect to data collection, processing and reporting, as they may exist from one trade publication to another.

Q. Why did you choose a Permian price index for comparison with California gas prices?

A. I did so because Permian is reflective of gas from the U.S. southwest states, which constitutes the major gas producing region for California. According to estimates of PG&E and Southern California Gas Company as reported in the 1994 California Gas Report, as documented in Exhibit No.____(BSA-4), approximately 66.2 percent of California's gas was derived from southwestern states in 1993, a figure which these companies projected to decrease to approximately 62.9 percent in 1994. Thus, the southwest has been and still is California's major gas supply region. I have used the Permian Basin index price as representative of the Southwest region because the Permian Basin is the most actively traded point west of the Texas-Louisiana Gulf Coast area. The Permian Basin's importance and activity is demonstrated by the Kansas City Board of Trade selecting the Permian Basin as the physical delivery point for its proposed gas futures contract.

Q. Do the basis differences to which you refer measure gas transportation costs?

A. Not exactly, because it is that and more. The price of gas at any large, actively-traded market center reflects the momentary gas supply and demand balance at that point. Weather, pipeline transportation costs to and from other centers, regional demand and temporary economic realities all have an effect on the local gas supply and demand balance. Hence they all affect the price of gas at that point at that time. It is a common fallacy to attribute basis differences throughout North America simply to transportation costs and nothing else.

Q. Do you agree with Ms. Walsh's statement that, "The only real and quantifiable benefit of the [PGT] expansion to pre-expansion shippers is the reduction in transportation fuel costs"?

A. No. Even though Ms. Walsh's Answering Testimony refers to the possibility of "gas-on-gas competition benefits" at several points (e.g., on page 33), such benefits are treated as unreal or nonquantifiable. In fact, PGT's 1993 Expansion produced a substantial and significant decrease in the cost of gas available to buyers in California, compared to the cost of gas in the major supply basin, Permian. As shown in Exhibit No.____(BSA-5), gas prices into California decreased by an average of $0.187 per MMBtu, as measured by the change in the basis difference between California border gas prices versus Permian Basin gas prices before and after the PGT Expansion went into effect.

Q. What were the time periods included in your analysis before versus after the PGT Expansion went into effect?

A. For the "before" period, I included in the analysis the period of time starting two months after the Kern River pipeline was delivered into service. As will be shown below, the Kern River pipeline also benefited California gas users. I therefore excluded the period of time preceding Kern River so as to isolate the effect of the PGT Expansion on California gas prices. The descending price data seen in Exhibit No.____(BSA-5) in the months immediately following Kern River's initial deliveries in February 1992 suggest that the market took a couple of months to adapt to the new reality of Kern River's significant expansion in capacity into California.

For the "after" period, I included in the analysis the period of time starting, again, a few months after the start-up of service on the PGT Expansion to skip the market adjustment period, through to the most recent month for which data were available in the preparation of this testimony, namely, February 1995.

It is clear from the exhibit that California gas buyers have twice reaped significant benefits of new pipeline capacity in the 1990s. Completion of the Kern River pipeline from Wyoming to California resulted in a $0.282 per MMBtu decrease in gas costs, measured as the before-versus-after decline in basis difference from Permian prices. This improvement in California's gas prices took place for precisely the same reason the PGT Expansion improved California's gas prices, namely, by enabling increased access to relatively lower-cost gas producing areas for California gas buyers.

Exhibit No.____(BSA-5) also shows the downward "steps" California's gas price basis difference has taken as a result of both pipeline capacity additions, PGT Expansion and Kern River. We refer to the "steps" in Exhibit No.___(BSA-5) as period average basis differences, i.e., over the periods defined above.

Q. Was the decline in California's gas price basis that followed the PGT Expansion significant in a statistical sense?

A. Yes, it was. I performed a simple linear regression on the foregoing step-shaped decline in the California gas price basis difference relative to Permian prices, and computed an R^2 statistic of 0.857, which indicates a statistically significant correlation. Had general competition in the gas industry been the major factor in reducing the gas price basis differences, it would have been more appropriate to approximate this set of points with a single straight line, instead of a step function. As a check, we computed the R^2 of a straight line through all five years of points from January 1990 through January 1995 in the graph in Exhibit No.____(BSA-5). In so doing, however, the R^2 fell to 0.836. We conclude as a consequence of this simple regression analysis that the stepwise decrease in basis difference caused by the impact of major new capacity additions accurately represents the decline in basis difference, even more so than does a single downward sloping line caused by general competitiveness. This line versus steps assessment is presented in Exhibit No.____(BSA-6).

Q. What is an R^2 statistic?

A. An R^2 statistic is used to measure how well two sets of data correlate with one another. The R^2 number varies from 1 to 0, meaning the two sets are perfectly correlated and that they are completely uncorrelated, respectively. R^2 number levels generally in excess of a range of 0.80 to 0.85 are usually considered indicative of significant correlation between data series.

Q. Could it be coincidental that the significant declines in the California gas price basis difference happened at the same times that the two pipeline expansions went into service?

A. No, there was no coincidence. The PGT Expansion and the Kern River pipeline each directly caused California gas prices to fall relative to Permian prices. To check whether the months of greatest decline were random, we turned the problem around, so to speak, and sought to use to data literally to tell us when the major capacity additions were delivered.

Exhibit No.____(BSA-7) compares, for each month during the past four years, the average basis for the period before versus after that month, i.e., how great the decline was. For example, the first row of the table in Exhibit No.____(BSA-7) indicates that the average Southern California-to- Permian basis during January 1990 was $0.615 per MMBtu (Columns B and C) and the average basis during the period from February 1990 through December 1994 was $0.413

per MMBtu (shown in Column D). The difference between these two period bases, therefore, is $0.202 per MMBtu as shown in Column E, i.e., the "mean before minus the mean after." The next row of the table indicates that the average basis during January 1990 through February 1990 was $0.633 per MMBtu (Column C), while the average basis during March 1990 through December 1994 was $0.410 (Column D), thus the mean-before-minus-the-mean-after (hereinafter, the "MBMA") equals the difference between these averages, namely, $0.223 per MMBtu, as shown in Column E. In similar fashion, the table in Exhibit No.____(BSA-7) indicates the MBMA for every month throughout the five years from January 1990 through December 1994.

Q. What is the significance of the MBMA as shown in Exhibit No.____(BSA-7)?

A. The MBMA peaked twice in the 1990s, as shown in the figure in Exhibit No.____(BSA-7), once in March 1992 and again in February 1994. These peaks took place when there occurred the sharpest, most pronounced differences between the average basis before that month versus after that month. We conclude that something major must have happened around the time the MBMA peaked to have caused these most significant decreases in Southern California-versus-Permian basis.

Q. What caused the MBMA peak when it did in Exhibit No.____(BSA-7)?

A. The Kern River pipeline and PGT Expansion each represented significant market changes which took place at those times. As can be seen in the figure in Exhibit No.____(BSA-7), MBMA was at its greatest level after the transition period when Kern River and PGT Expansion went into service. The analysis in Exhibit No.____(BSA-7) clearly and vividly demonstrates that (a) the California gas price basis experienced its greatest extended declines when significant pipeline capacity was added, and that (b) examination of the gas price basis data alone could have predicted when the expansions, in fact, took place. In other words, simply put, if we did not know when the Kern River and PGT Expansion capacity additions went into service, we need only look at gas prices - the gas price basis differentials are clear enough on this point that they, alone, are capable of telling us when these new services were added.

Q. Could the decline in basis following the PGT Expansion have been caused by Order No. 636?

A. No. Order No. 636 implementation was phased-in among the nation's major pipelines, and, therefore, its effect could not have come about suddenly, i.e., in the sense that PGT Expansion was opened all at once on November 1, 1993. Moreover, some pipelines adopted SFV rate design starting nearly a year earlier.

Q. Would your analysis and conclusions have differed had you

used gas price data from a trade publication other than GMR?
A. No, the results and conclusions would be the same. As a check, I replicated the analysis of Exhibit No.____(BSA-5), using data from NGI and NGW, rather than GMR. As can be seen in Exhibit No.____(BSA-8), the results conformed to those obtained using GMR.
Q. Could the results be explained by the weather?
A. No. In fact, we investigated whether the results were caused by weather. We found that they were not and that the price differences would have been even larger if we had normalized for weather.
Q. At what point did you measure the California border price?
A. At Topock, which is the delivery point at the Colorado River from El Paso and Transwestern into the facilities of Southern California Gas Company and PG&E.
Q. If your analysis had considered gas delivered by Transwestern, would the results have been the same?
A. Yes, they would have. The spot prices for gas on both Transwestern and El Paso are nearly identical, with the nearly perfect R^2 relationship of 0.989. The mean price for El Paso throughout the period was $1.66/MMBtu; the mean price for Transwestern was $1.65/MMBtu. Therefore, not only do the two pipelines' gas markets correlate almost perfectly, they have essentially the same values as well.
Q. If you had used the San Juan Basin price index instead of

the Permian Basin price index, would the results have been the same?

A. Essentially, yes. As seen in Exhibit No.____(BSA-9), the step function is almost equally apparent using San Juan as the major supply basin, rather than the Permian Basin.

Q. In summary, what is the extent of the benefit which the PGT Expansion conferred on California gas users?

A. I conclude that California gas customers began receiving a benefit of approximately $382 million per year in the form of lower gas prices as a result of the completion of the PGT expansion system.

Q. How do you arrive at the foregoing estimate?

A. As seen in Exhibit No.____(BSA-10), I multiplied monthly gas consumption for California, taken from the Natural Gas Monthly, by the monthly price basis differentials experienced since the PGT Expansion. I then took the average monthly cost to California due to the differentials and multiplied this number by twelve to arrive at the yearly cost. I repeated the foregoing steps for each of the three periods of time in the analysis (i.e., pre-Kern River, Kern River to PGT Expansion, and PGT Expansion through the present). The difference in the State's total gas cost before and after the Kern River opening is the benefit to gas consumers caused by Kern River. The difference in the State's total gas cost due to differentials before and after the PGT Expansion is the benefit to gas consumers created by the PGT Expansion. Note that in each case (Kern River and PGT Expansion), I excluded the build-up of benefits that accrued during the transition period that followed each new capacity expansion, but, instead, developed a benefits estimate which is reflective of the steady-state for forecast purposes.

Q. How much of the foregoing benefits accrue to PG&E, and to PG&E's core markets?

A. PG&E's customers receives $162 million in gas cost benefit annually as a result of the PGT Expansion, and PG&E's core markets receive $54 million. I prepared this estimate based on each sub-market's share of state-wide gas volumes, as follows:

Table BSA-1

Market	Annual Volume (Bcf)	Percent of State	Benefit (10^6)	Impact of PGT Roll-In (10^6)	Net Benefit (10^6)
Statewide	2,043	100.00%	382	30	352
PG&E	864	42.29%	162	52	110
PG&E Core	290	14.19%	54	29	25

Sources: Natural Gas Monthly, 1994 California Gas Report; PGT response to EPNG-1 Data Request No. 9; Exhibit No.____(HTA-2)

Note that in the foregoing table, I have subtracted the total allocated cost of roll-in of PGT's rates which each class will have to bear, to arrive at an estimate of the net benefit experienced by California gas users, PG&E's gas users, and PG&E's core market gas users, respectively.

Q. Please summarize why the foregoing benefit has taken place.

A. The California gas cost benefit of $382 million per year due to the PGT Expansion was caused by increased gas price competition among producers, pipelines, and marketers supplying California which, in turn, resulted from the opening to California of significantly more volumes of lower-priced gas from Alberta than could otherwise reach California.

Simply put, El Paso and Transwestern transport gas from the Permian and San Juan supply basins. PGT delivers gas from a completely different supply basin, Alberta. Canadian gas has historically cost significantly less than gas from the Southwest, as has Rocky Mountain gas. As Exhibit No.____(BSA-11) shows, over the past five years, Permian gas averaged $1.658/dth, gas in the Rockies averaged $1.462/MMBtu, and gas from Canada averaged only $1.150/MMBtu (in U.S. dollars). This is clearly why the opening of the Kern River pipeline and the PGT Expansion each had such a large effect. They brought to the marketplace gas from relatively lower-cost supply areas.

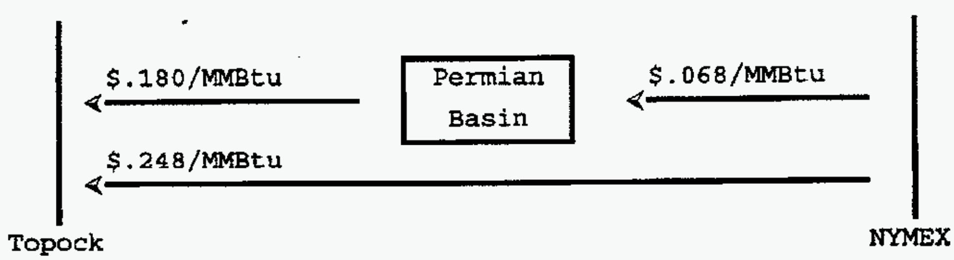
Q. How is your analysis different from that presented by Southern California Edison Company witness Andrew Van Horn?

A. As I understand Dr. Van Horn's testimony in this proceeding, he has constructed an econometric model of natural gas price formation in the California market, using a representation of "slack capacity" into the market as one of his independent variables. My analysis is not an econometric model, nor indeed, a model of any sort. I have simply tested, using statistical techniques, and common sense, whether the changes in the actual, recorded price differences between the California market and the Southwest supply basins are better explained by general competition in the marketplace or by the specific additions of new pipeline capacity from low-cost supply areas to the California market. As the foregoing analysis shows, the price basis changes are better explained by the addition of new pipeline capacity.

Q. In addition to "slack capacity" Dr. Van Horn's model also relates California gas prices to closing prices for the NYMEX gas futures contract. Did you also consider NYMEX in your analysis?

A. Yes. NYMEX prices represent the North American continent's most actively traded trading location, namely Henry Hub in Erath, Louisiana. In examining NYMEX, I found that the California to NYMEX price differences, as well as the Permian Basin and San Juan Basin to NYMEX differences, all declined. Exhibit No.___(BSA-12) provides comparisons of these differences through November, 1994. As this exhibit clearly shows, both Permian Basin and San Juan Basin price differences relative to NYMEX decreased in essentially the same fashion as did California-to-Permian basis differences, as follows: The Permian to NYMEX basis difference declined by $.068 per MMBtu after the PGT Expansion relative to the preceding period, and the San Juan to NYMEX basis difference likewise declined by $.093 per MMBtu after the PGT Expansion relative to the preceding period. Consequently, 27.4 percent of the total decline in the California (Topock) to NYMEX price difference of $.248 per MMBtu came as a result of the $0.68 per MMBtu decline in the Permian to NYMEX basis difference.

Graphically, the foregoing relationships may be illustrated as follows:



Q. Ms. Walsh apparently believes that a benefits calculation at the California border is not valid because "PG&E purchases all cf its Canadian gas supplies for its core customers in

Alberta. Similarly, PG&E buys nearly all of its Southwest gas supplies in the San Juan, Permian, and Anadarko producing basins using its firm capacity rights on interstate pipelines." Is that a valid criticism?

A. No, it is not for several reasons. First and foremost, the foregoing discussion and analysis clearly shows that all gas markets in North America are inextricably connected with one another. Gas that, because of increased competition, became less costly in California as a result of the PGT Expansion forced, in turn, gas in California's supply basins to likewise become less costly. This point is demonstrated by the results shown in Exhibit No.____(BSA-12), namely, that gas prices in the Permian and San Juan Basins also declined after the PGT Expansion. Consequently, PG&E's core customers have enjoyed relatively lower gas costs as a result of the PGT Expansion. Indeed, the gas cost competitive benefits of the PGT Expansion were undoubtedly felt at the Henry Hub too, with the result that NYMEX prices themselves were relatively reduced as a result of the infusion of the PGT Expansion's 903 MMcf/d of low-cost Alberta supplies into the American market. While price changes at NYMEX are difficult to pin down, the effect is real enough.

Second, and related to the foregoing, if gas became less costly at the California border after the PGT

Expansion, as it in fact has, then for Ms. Walsh to argue that PG&E and other basin-indexed purchasers fail to receive a benefit completely flies in the face of market realities. In proffering such an argument in her Answering Testimony, Ms. Walsh would have the Commission believe that there exists some kind of mythical "brick wall" separating the gas markets of North America, including both supply and end-use markets. But there are no such "brick walls" in the gas market today. In reality, however, the gas markets at the California border which we rely on in this analysis consist of markets for gas delivered to the California utilities, as well as its end-users.

Thus, in summary to this point, the reduction in California border prices induced by the competitive effects of the PGT Expansion caused a reduction in Southwest Basin prices, as documented in Exhibit No.____ (BSA-12), and undoubtedly in NYMEX prices as well. Therefore, PG&E and others that purchase Southwest gas on any market-based indices have received direct benefits from the PGT Expansion.

Q. Is the decline in basis due to lower cost transportation and/or pipeline discounting, as Ms. Walsh suggests in her Cross-Answering Testimony?

A. Only in part. But Ms. Walsh has it backwards, since the cause and effect relationship goes like this: Because of the competition it feared as Kern River was about to come on line, El Paso reduced its volumetric rates. As Kern River was about to go into service, El Paso filed before the FERC to extend the amortization period for its volumetric surcharge, thereby reducing its take-or-pay add-on to 3.55 cents per MMBtu. As stated in by El Paso in Docket No. RP92-115-000:

> An extension and consolidation of El Paso's surcharge amortization periods is warranted by the developments in the market in which El Paso competes and is fully consistent with the public interest. Within the next few weeks, a newly constructed pipeline operated by Kern River Transmission Company ("Kern River") will commence service to the California market and certain other market areas served by El Paso (footnote omitted)

El Paso also cites its competition with Transwestern, which had essentially eliminated its take-or-pay surcharges by this time, as additional evidence for the need for the surcharge reduction.

Relevant portions of El Paso's pleading are appended hereto as Exhibit No.____(BSA-13). Clearly and unequivocally, El Paso slashed its price for transportation because of the advent of new pipeline capacity accessing a relatively low-cost supply area, whose delivered gas cost to market would be lower than El Paso's. Ms. Walsh's effort in her Cross-Answering Testimony to somehow use this fact to argue against roll-in is misplaced.

Q. Was all of the decline in basis difference between California and the Permian Basin due to reduced pipeline transportation costs?

A. Not directly. The decline in basis between California and the Permian Basin resulted from an increase in competition to supply California's gas markets in all respects, including suppliers and transporters. Indeed, that the decline could not have resulted solely from reduced pipeline transportation costs is illustrated in Exhibit No.____(BSA-14), which summarizes El Paso's discounted transportation costs for interruptible transportation shippers all the way to California. Apart from the period during the early 1990s when El Paso's costs to IT shippers were relatively high due to the short take-or-pay amortization period then in effect, no major change in El Paso's costs to IT shippers is evident from the chart in Exhibit No.____(BSA-14), certainly none that would indicate that El Paso's volumetric costs could possibly be used to explain the significant decline in California-to-Permian price basis difference, as Ms. Walsh's Cross-Answering Testimony (Exhibit No.____(NFW-40)) at page 8 would have us believe.

Exhibit No.____(BSA-14) was derived from El Paso's transportation discount reports filed at the FERC on a monthly basis throughout the 1990s. It should be noted that these data do not include the volumes of discounted transportation, nor do they include non-discounted transportation. Moreover, there are no El Paso transportation discount reports on file at the FERC for a number of months in the 1990s, and for some of the reports on file there are no long-haul discounts reported. Most of these months are clustered in the 1992-1993 period when California's buy-sell programs were in effect as a means of "capacity release" for California shippers.

Nonetheless, despite the foregoing limitations, the information in Exhibit No.____(BSA-14) is an explicit indication of the kinds of transportation costs that were available to California shippers, and thus the price of transportation on El Paso. Again, such costs bear no resemblance to the major decrease in California-to-Permian price basis difference that occurred after the PGT Expansion was placed in service.

Q. Did El Paso or Transwestern significantly change their discounting behavior toward any interruptible transportation shippers after the PGT Expansion went into effect?

A. In the aggregate, not significantly. Based on discount reports filed with the FERC, the discounting behavior of El Paso and Transwestern did not change significantly before versus after the PGT Expansion went into service, for their shippers in general. As Exhibit No.____(BSA-15) shows, El

Paso's discounts during the first nine months of 1993 for which such reports are available were in the range of 58% to 63%. During the same nine month period in 1994, El Paso's reported discounts ranged from 62% to 66%, a rather mild increase. Likewise, Transwestern reported discounting transportation in January-August 1993 by 52% to 61%, and by 46% to 68% during January-September 1994, again a modest change in discounting behavior at best. The only conclusion possible from these data filed by El Paso and Transwestern with the FERC is that neither pipeline's transportation discounting behavior changed significantly from 1993 to 1994. In summary, while we cannot exclude pipeline discounting as explaining some of the decline in basis after PGT Expansion, it clearly does not explain it all.

IV. So-Called "Stranded Costs" and the Reality of Gas Competition Benefits

Q. What are so-called "stranded costs" referred to throughout Ms. Walsh's and Dr. Weisenmiller's testimony, and how do they relate to these proceedings?

A. I understand so-called "stranded costs" in Ms. Walsh's and Dr. Weisenmiller's testimony to mean gas transportation costs incurred, for example, by PG&E as a result of a purported decrease in the value of capacity on interstate pipelines such as El Paso. However, I also understand that the so-called "stranded costs" are not new costs imposed on

California, since the so-called "stranded costs" are just a subset of interstate pipeline charges that California entities have been paying for a long time. Ms. Walsh and Dr. Weisenmiller attribute much, if not all of these "costs" to the PGT Expansion. In fact, the value of capacity on El Paso in the capacity release market did decline after PGT's Expansion because that Expansion opened to California markets 766 MMcf per day of relatively low-cost gas which could not previously be delivered to the state, and buyers increased their purchases of the newly-available lower-cost alternative supplies, i.e., by filling the Expansion capacity, but not to the extent Ms. Walsh claims. The total decline in the value of pipeline capacity from the southwest is reasonably portrayed by the chart on page 8 of Ms. Walsh's Exhibit No.____(NFW-19), but the causality is not reasonably portrayed.

As seen in Column (17) of the chart in Exhibit No.____(BSA-16), the average difference between PG&E's demand charge obligation to El Paso for the capacity offered for release and the revenues received from replacement shippers (the "Remaining Obligation") in the three months before the PGT Expansion (i.e., from August 1993 through October 1993) was $4,046,000 per month, while the average "Remaining Obligation" in the nine months after the Expansion (i.e., from November 1993 through July 1994) was

$4,960,000 per month. Even if we exclude as a market transition period the first three months the PGT Expansion was in effect, the average Remaining Obligation during February through July 1994 in the remaining six months in the chart was $5,034,000 per month. The difference of $988,000 per month represents the increase in revenue that PG&E could not recover from replacement shippers as a result of the reduced market value of capacity on El Paso after versus before November 1, 1993. That decline on an annualized basis is $988,000 times 12, which equals approximately $11.9 million.

As far as any so-called "stranded costs" on PGT's pre-Expansion capacity is concerned, Ms. Walsh's Answering Testimony contains argument, but her Exhibit No.____(NFW-19) shows that PG&E's revenue from capacity release on PGT is less than the full demand charges PG&E pays for the capacity offered for release. But this Exhibit contains absolutely no evidence of any so-called "stranded cost" to PG&E on pre-Expansion PGT capacity that is due to the PGT Expansion. Because PGT's capacity release program began contemporaneously with the PGT Expansion in November 1993, there is no "before" period with which to compare PG&E's revenues from release of PGT capacity with capacity release revenues received after the Expansion. Ms. Walsh's inclusion of post-Expansion figures in her assessment of so-called "stranded costs" is based solely on the speculation that somehow the PGT Expansion took gas off PGT's pre-Expansion system, a speculation for which she provides absolutely no basis.

Q. On page 51 of her Answering Testimony, Ms. Walsh states "In the 12-month period ended July 1994, the total stranded costs of PG&E's El Paso capacity was (sic) approximately $80 million." Please comment.

A. The $80 million figure is a big number, but it has no relevance to these proceedings. Part of Ms. Walsh's alleged $80 million in so-called "stranded costs" became "stranded" before the PGT Expansion ever went into service in November 1993, according to Exhibit No. _____ (NFW-19). Moreover, in her calculation later in that testimony of so-called "stranded costs" attributable to the PGT Expansion, Ms. Walsh on pp. 55-56 effectively reduces her estimate to $19.9 million, i.e., the $25.8 million cited on page 56, line 5, minus $5.9 million of that amount consisting of purportedly stranded costs on PGT's pre-Expansion capacity referred to on page 55 of her Answering Testimony (Exhibit No.____(NFW-1)). Ms. Walsh's only justification for including this $5.9 million figure is the simplistic argument that "it is very unlikely that PG&E would have had any stranded costs associated with the PGT capacity." (emphasis in original)

Additionally, the $80 million figure is unsupported by the information supplied by Ms. Walsh in Exhibit No.____(NFW-19), since it includes portions of PG&E's capacity on El Paso which PG&E did not even offer for release. In other words, how can we blame PGT Expansion for "stranding" costs for capacity which PG&E evidently needed enough to withhold from the release market?

Q. Ms. Walsh refers at page 56 of her Answering Testimony to the $25.8 million estimate of so-called "stranded costs" as "conservative." Do you agree?.

A. No, I do not. Ms. Walsh's estimate of $25.8 million of so-called "stranded costs" experienced by PG&E is substantially overstated for the following reasons:

First, Ms. Walsh's $25.8 million figure includes capacity on El Paso that PG&E did not seek to release, and thus could not have been "stranded" by the PGT Expansion (or by anything else, for that matter).

Second, Ms. Walsh's estimate includes $5.9 million of so-called "stranded costs" on PGT without adequate justification, as I outlined above.

Third, initial service on the PGT Expansion in November 1993 was coincident with the implementation of Order No. 636 capacity release on PGT. Ms. Walsh's figures do not take into consideration the effect that capacity release on PGT's pre-Expansion capacity had on the price of released capacity on El Paso, which certainly would have been to reduce the price of El Paso released capacity and increase discounting by El Paso. This competitive effect is related exclusively to Order No. 636 and therefore would have been present even without the presence of the PGT Expansion facilities.

Consequently, for all of the foregoing reasons, Ms. Walsh's estimate of $25.8 million of so-called "stranded costs" incurred by PG&E as a result of the PGT Expansion is quite overstated. Indeed, such costs may not exist at all.

Q. Earlier, on p. 36 of her Answering Testimony (Exhibit No.____(NFW-1)), Ms. Walsh argues that California gas users have had to pay "...$149 million in stranded costs of interstate pipeline capacity for the 12-month period from August 1993 through July 1994, caused by the overbuilding of interstate pipeline to California since 1992 and severely exacerbated by the PGT expansion." Please comment.

A. The $149 million figure is an even bigger number, with even less meaning. The $149 million number presented by Ms. Walsh is inconsistent with the advent of the PGT Expansion because it spans a period of 3 months before the PGT Expansion went into effect on November 1, 1993. Consequently, much of the purported stranded capacity costs calculated by Ms. Walsh took place before the PGT Expansion opened for business. Moreover, a portion of the $149 million figure includes: (1) "stranded costs" for all of

California, not just PG&E; (2) "stranded costs" allegedly caused by pipelines other than the PGT Expansion; and (3) "stranded costs" for capacity for which California gas utilities made good use, or expected it would because it never offered this capacity for release.

Q. Finally, on p. 4 of his Cross-Answering Testimony (Exhibit No.____(RBW-99)), Dr. Weisenmiller speaks of a $500 million amount of so-called "stranded costs." Please comment.

A. This is the biggest "stranded cost" number yet, with the least meaning of all. Dr. Weisenmiller has puffed up his estimate of so-called "stranded costs" into a multi-year behemoth generally inclusive of all costs related to PG&E's transportation service for a five-year period, to meet core needs. In presenting this number, Dr. Weisenmiller ignores the period for which there are actual data on so-called "stranded costs," and uses his hypothetical figures instead.

Dr. Weisenmiller's $500 million figure is merely a 50-month version of a $240 million figure found earlier in his testimony; and the $240 million figure is derived from an unidentified PG&E projection, which is apparently reproduced in Exhibit No.____(RBW-102), of costs for capacity that PG&E evidently expects to use to serve its core markets. Consequently, Dr. Weisenmiller's highly exaggerated number ignores: (1) the usefulness of these contractual assets to PG&E or its customers; (2) any notion of whether these "stranded costs" become "stranded before or after the PGT Expansion (it is mostly before); (3) whether these "stranded costs" can be attributed to pipelines other than the PGT Expansion (some certainly can); (4) the extent to which Order No. 636 capacity release on PGT's pre-Expansion capacity contributed to these "stranded costs;" and (5) the fact that the creation of a secondary market for capacity under Order No. 636 has had on the commoditization of pipeline capacity, enabling the value of the capacity to be identified and monetized. Still, on page 4 of Dr. Weisenmiller's Cross-Answering Testimony, we are then advised that his winning $500 million estimate of PG&E's so-called "stranded costs" is seriously understated because it excludes Southern California Gas Company. Overall, Dr. Weisenmiller's characterization of so-called "stranded costs" is meaningless and useless.

Q. Please summarize the information you believe the FERC should consider about the so-called "stranded costs" issue.

A. The FERC should ignore the contest among opposing witnesses to beef up the heftiest estimate of so-called "stranded costs." As Ms. Rosput discusses, so-called "stranded costs" are a red herring (Exhibit No.____(PGR-1)). However, should the Commission seek for any reason, to quantify the effect of pipeline-to-pipeline competition, it must include careful analysis of:

(a) the market realities of the commoditization of interstate pipeline capacity that followed this Commission's Order No. 636, and its effect on capacity values;

(b) what portion of the growth in the shortfall, if any, is correctly attributable to the PGT Expansion, Kern River, or any other capacity additions, including those by El Paso and Transwestern; and

(c) how such growth in shortfall, if any, is actually allocated among PG&E's customer classes.

Considered accurately in light of the foregoing, the only relevant estimate of PG&E's so-called "stranded costs" that is on the table at this point is the $11.9 million figure I developed above in this testimony, which excludes the effects of Order No. 636. Moreover, these costs would only last until PG&E's contract with El Paso expires on December 31, 1997. After that, the competitive benefits will continue by any possible "stranded costs" on El Paso will disappear entirely for PG&E.

V. Benefits of PGT Expansion Flow to All California Customers

Q. Which gas customers in California are experiencing the gas cost benefits of the PGT Expansion?

A. All the State's gas customers whose gas prices are tied to market levels.

Q. To what extent is gas purchased by PG&E at prices that are tied to market levels?

A. PG&E's gas purchases for both core and noncore markets must, of necessity, reflect market values, a principle well-established in gas cost recovery and purchase prudence proceedings before the CPUC. Thus I was not surprised to learn from the data response from the CPUC that PG&E's purchases are virtually all either spot, or indexed to spot, or otherwise tied directly to market prices. Moreover, all of these contracts are relatively short-term in nature, and therefore are renegotiated regularly in a way that keeps them responsive to markets. (*See* Exhibit No.____(BSA-17)).

Q. PG&E is in the Northern part of California, and receives Canadian gas via PGT's delivery point at Malin, Oregon. Do the results of your analysis of gas prices at Topock still apply to PG&E?

A. Yes, they do apply in full. The fact that PG&E's deliveries from PGT and its gas markets are located in the northern part of the state is not important from a perspective of the distribution of the gas cost benefits of the PGT Expansion to the State's northern gas users. To check this, I tested gas prices at Malin against prices at Topock to determine the extent of market consistency. As can be seen in Exhibit No.____(BSA-18), Topock and Malin prices have correlated with the near perfect R^2 of 0.992 since the lifting of the

Canadian export restrictions, i.e., the most recent period for which data are available that enable such a comparison, and the time following the PGT Expansion.

This correlation tells us that these locations are nearly perfect proxies for one another and that, in fact, the Northern and Southern California gas markets are one single market. This should surprise no one, since competition within the natural gas industry has continually drawn the major markets, hence their indices, into closer and closer conformity with one another.

Q. Do you agree with Ms. Walsh that "...the 422,529,000 MMBtu of noncore/wholesale demand is the maximum volume which should be considered in the benefit calculation?"

A. No. Again, Ms. Walsh argues that some kind of brick wall separates core from noncore gas purchases in California. In reality, of course, California's gas markets are so deeply intertwined that there is only one single statewide gas market, as I discussed above. PG&E's core market gas customers receive gas under contracts in which PG&E's gas price is clearly and of necessity tied to gas market prices. Consequently, a decline in the relative price paid by one segment cannot be sustained in the current fluid, flexible gas market without a similar decline in the relative price paid by the other segment, as long as both segments are purchasing gas at market indices. Indeed, both core and noncore gas markets in California have shared alike in the significant gas cost savings that followed the PGT Expansion.

VI. Pacific Northwest Benefits of PGT Expansion

Q. Mr. Sullivan of Washington Natural Gas Company claims that the PGT Expansion has not provided benefits to gas users in the Pacific Northwest. Mr. Stoltz of Cascade Natural Gas Corporation also questions the existence of gas competition benefits in the Pacific Northwest. Are there gas competition benefits to gas users in the Pacific Northwest as a result of the PGT Expansion?

A. There are. The PGT Expansion benefited gas users in the Pacific Northwest by engendering increased competition in the three states area, including Washington, Oregon, and Idaho. This added competition has resulted in relatively lower gas prices in the Pacific Northwest than would otherwise have been the case.

Q. What is the extent of gas demand in the Pacific Northwest Region?

A. As seen in Exhibit No.____(BSA-19), the three states comprising the Pacific Northwest Region used 380.7 trillion BTUs (TBtu) of gas in 1993, more than any year in the 19[illegible]0s. By comparison, gas use in California was more than 2 quadrillion Btus in 1993, i.e., five times the gas use of the Pacific Northwest.

Exhibit No.____(BSA-20) compares spot gas prices in each of the three major producing regions supplying gas to the Pacific Northwest--the Rocky Mountains, British Columbia, and Alberta. Prices for these regions are represented in the exhibit respectively by spot price indices at:

- Sumas, *i.e.*, the price of gas at the delivery point of Westcoast Transmission into Northwest Pipeline;
- Rockies, *i.e.*, the average of reported prices into Northwest Pipeline at its Rocky Mountain receipt points;
- Alberta, *i.e.*, the reported price of gas FOB the NOVA Pipeline in Alberta, for export out of the province.

From this Exhibit, I conclude that gas prices at each of the three locations have born a significant correlation to one another since 1990, and statistical analysis bears this out. As shown in Exhibit No.____(BSA-20), R^2 values among all combinations of the foregoing three gas price indices are all within the range of approximately 69 to 84 percent. I note that the lowest of these correlations was that between gas prices in the Rockies and at Sumas, which was 61 percent. This indicates the lowest degree of price correlation within the Pacific Northwest's gas producing regions.

Q. Have you reviewed city gate prices in the Pacific Northwest in your analysis?

A. Yes, I did. I reviewed gas prices at the Seattle city-gate as reported by Inside FERC's Gas Market Report from 1991 through the present. These are the only data to which I had access that reflect gas prices at the point where customers in the Pacific Northwest would actually purchase gas. An exception to the direct applicability of the foregoing data would be, for example, a gas buyer contracting in the field and then carrying the gas using its own firm transportation.

Q. How have you analyzed Seattle City Gate prices referenced above?

A. I compared these prices with the field prices identified in Exhibit No.____(BSA-20). I then calculated gas price differentials between Seattle City Gate prices and prices reflective of each of the three gas supplier regions to the Pacific Northwest. In other words, the Seattle City Gate Basis relative to Rockies, Sumas and Alberta prices. Exhibit No.____(BSA-21) presents the results of this analysis. As in the California analysis discussed earlier in my testimony, I then calculated the period average bases in each case, for the following three periods of time:

(1) from January 1991 through the initial deliveries of Kern River Pipeline gas to California customers,

(2) from the Kern River pipeline to the initial deliveries of gas from the PGT Expansion in November 1993, and

(3) from February 1994 through the most recent month for which sufficient information was available to perform the comparison.

Exhibit No.____(BSA-21) illustrates the foregoing period average bases as a series of horizontal lines in the figures in the Exhibit.

Q. What do you conclude from Exhibit No.____(BSA-21)?

A. I conclude as was the case in the preceding analysis of California gas prices, that average Seattle City Gate versus producing region bases generally declined after PGT Expansion began delivering large volumes of relatively lower cost gas to the customer regions.

Q. What was the degree of benefit experienced by gas users in the Pacific Northwest states as a result of the entry of PGT's expansion into the marketplace?

A. The benefit to Pacific Northwest gas customers is approximately $16.2 million annually, based on the improvement in Seattle City Gate prices relative to the two major gas producing regions on which the region relies for its gas supplies. Specifically, I calculated this benefit amount as equal to the average of:

- the decline in basis between Seattle City Gate and

Sumas after PGT Expansion, i.e., \$0.294 per MMBtu minus \$0.181 equals \$0.113 per MMBtu; and

- the decline in basis between Seattle City Gate and Rockies after PGT Expansion, i.e., \$0.151 per MMBtu minus \$0.179 equals -\$0.028 per MMBtu.

The average basis decrease equals \$0.0425 per MMBtu. I then multiplied the \$0.0425 times total gas consumption in the Pacific Northwest of 380.7 TBtu in 1993 to yield an approximate \$16.2 million in benefit in 1993.

Q. Why did you use both the Rockies and Sumas price indices to calculate benefits?

A. As seen in Exhibit No.____(BSA-22), from data submitted in response to PGT's request in this proceeding, 96.5% of Cascade's spot gas purchases come from domestic U.S. sources and from Sumas, i.e., 57.1% from the U.S. and 39.1% from British Columbia. Washington Natural's responses cannot be used in this context because the information supplied merges Alberta and British Columbia purchases into a single category, Canada.

Returning to Cascade's response, the information Cascade supplied did not enable a determination as to which of these two sources (B.C. and domestic) constitutes the region's marginal gas supply, i.e., that from which the marginal unit of gas is purchased. Clearly, however, these two sources contribute the overwhelming preponderance of gas supplies to the Pacific Northwest, thus both must be taken into account in the benefits calculation. I weight them evenly because the data to which I had access was incomplete relative to which producing regions supply gas to the Pacific Northwest in exact measure.

Q. Will gas consumption in the Pacific Northwest decline, thus reducing the level of benefits to the region resulting from competition?

A. It is difficult to find credible sources that project a decline in gas demand in the Pacific Northwest. The region's gas utilities forecast an aggregate 2 percent annual demand growth through 2010 in their respective Least Cost Plans (these forecasts exclude gas for electricity generation). In fact, gas demand in the Pacific Northwest is increasing for the right reason, because gas is a more economical fuel that fuel oil or other alternatives available to many energy users. In addition, major new independent electricity generating facilities in the Pacific Northwest include those in Ferndale and Bellingham, Washington, and in Hermiston, Oregon. Finally, the natural gas vehicle market, which is now only beginning to be a measurable contributor to gas demand, is expected to increase in the 10-20 year time frame.

Q. Does the increase in Seattle City Gate to Rockies basis that followed the PGT Expansion according to your Exhibit

No.____(BSA-21) undermine your conclusion as to the existence of a benefit due to competition?

A. No, it does not. The increase in average Seattle to Rockies price basis in 1994 of $0.028 per MMBtu was minor compared to the decrease in Seattle to Sumas price basis of $0.113 per MMBtu over the same period of time. Moreover, consumers accessing Northwest Pipeline have the ability to shift their purchases between the Rocky Mountains and British Columbia (Sumas) if price conditions warrant.

Q. Could the benefit you calculated have resulted strictly from transportation discounting?

A. No. As was the case for the pipelines serving California from California's traditional Permian and San Juan supply basins, namely El Paso and Transwestern, Northwest's interruptible discounts in 1994 were generally the same as they were in 1993, as shown in Exhibit No.____(BSA-23). This leads me to believe that the average decline in basis of $0.0425 per MMBtu was more a result of intermarket competition, and cannot be attributed solely to transportation pricing.

Q. Had you used a different publication from Inside FERC's Gas Market Report to conduct your analysis, would your results have changed?

A. No, not at all. Exhibit No.____(BSA-24) compares supply basin data for the Pacific Northwest as obtained from three different publications, i.e., Inside FERC's Gas Market Report, Natural Gas Intelligence and Natural Gas Week. The results show clearly that it would not have made much difference had I used either of the other two publications as a basis for Exhibit No.____(BSA-21).

In sum, the foregoing analysis effectively rebuts such negative assessments of the PGT Expansion. Although the gas cost benefits that I have documented to gas buyers in the Pacific Northwest states are clearly not nearly as great as the analogous benefits to California gas buyers, this testimony demonstrates that the PGT Expansion has benefited buyers in the Pacific Northwest.

VII. Natural Gas Vehicle (NGV) Market Benefits

Q. In his prepared direct testimony on page 62, Dr. Weisenmiller criticizes PGT's analysis because he says it "...fails to reflect [such costs as NGV development, conversion and service stations]." Is this criticism relevant in a net benefits calculation?

A. No, not at all. Dr. Weisenmiller's enumeration of costs ignores the monetary benefits of NGVs to their users, and to society as a whole. Mr. Ash documents several of these benefits in his testimony. Certainly these benefits should be considered at least at the level proposed by PGT, since it is a conservative estimate of the potential. These benefits are substantial in dollar terms, and will far outweigh NGV program development and fueling system costs.

Q. What is the basis of your statement that NGV benefits outweigh the costs?

A. Although no comprehensive analysis as yet exists of the benefits and costs of NGV programs in the Pacific region, simple operating realities make the potential clear. NGVs currently cost an additional $2,000 to $3,000 at dealers for new vehicles or conversions. However, NGVs operate with the same fuel efficiency on a fuel (natural gas) that costs considerably less than gasoline, enough so to more than offset the added vehicle cost for the targeted market, namely, fleet vehicles with high annual mileage. To illustrate, regular-blend charge-card gasoline currently costs in the range of $1.20 to $1.30 per gallon, while compressed natural gas (with all commodity, pipeline, distribution, compression and service station costs added in) currently costs in the range of $0.80 to $0.90 per gallon equivalent, or a difference of approximately $0.40 per gallon. At an average of $0.40 per gallon, a fleet NGV consuming 15 miles per gallon equivalent and traveling an average of 150 miles daily for 300 days per year, will save $1,200 annually, thus will "pay off" the added initial cost in approximately two years. Over the next three years of a five-year useful life, the NGV will save its owner approximately $3,600. Assuming 50,000 NGVs are in use in

California (requiring less than 20 TBtu annually), the annual savings in vehicle operating cost to owners will be approximately $180 million annually after the initial two-year break-even period. Although this example is illustrative in nature, it demonstrates that fuel price differences alone between gasoline and natural gas are great enough to potentially return substantial dollar benefits to California NGV fleet operators, ergo, to California's economy.

Q. On the same page, however, Dr. Weisenmiller adds that "[Regulators typically balance] the marginal costs of these programs with the marginal social benefits...so that there are no benefits 'left-over' which PGT can claim for off-setting to costs of roll-in." Do you agree?

A. Not at all. Dr. Weisenmiller's assertion ignores the rather substantial NGV fleet operator benefits due to the lower operating cost of compressed natural gas than gasoline, which the foregoing example makes clear. Such benefits are the direct result of the added growth in gas markets that is enabled by PGT's expansion. Even if, as Dr. Weisenmiller's testimony suggests, some regulators ignore such benefits (and I do not agree that all regulators ignore them), Dr. Weisenmiller has shown no reason why the FERC should ignore such benefits of the PGT Expansion in this proceeding.

VII. Summary

Q. Dr. Schlesinger, can you please summarize your testimony?

A. Whenever major new supplies of lower-cost gas supplies entered California and, to a lesser extent, the Pacific Northwest states in the 1990s, the gas-to-gas market competition that ensued resulted in lower gas costs to the consuming regions than would otherwise have been experienced. In particular, in the case of PGT's Expansion, this benefit is measurable and, in the case of California, enormous (at least $382 million annually). Such a benefit cannot be ignored by the FERC in any balanced assessment of the net benefits of the PGT Expansion. Moreover, growth in the region's gas use of an additional 280 TBtu per year is enabled by the PGT Expansion. To the extent that growth is channeled toward such traditional and non-traditional uses that are economic, e.g., electricity generation and NGVs, the PGT Expansion is producing added benefits to the region.

Q. Why did you state that the competition benefits to California gas users is "at least" $382 million annually?

A. The competition benefits to California gas users is "at least" $382 million annually as a result of the PGT Expansion because this benefit calculation ignores the substantial benefit engendered as a result of the decline in the Permian Basin and San Juan Basin to NYMEX prices differences, which coincided with the initial deliveries of gas from the PGT Expansion. Moreover, my estimate does not include any decrease in NYMEX prices as a result of the PGT Expansion. Finally my estimate excludes the substantial benefits to vehicle operators, which are enabled by the PGT Expansion when the added gas is consumed in NGVs.

Q. Does this complete your testimony, Dr. Schlesinger?

A. Yes, it does.

CORRECTED *REBUTTAL* TESTIMONY OF BENJAMIN SCHLESINGER, PH.D.

Pg #	Line #	TEXT: including ~~strikeout~~ and insert text
7	48	Basin. Also appropriate would be the difference between Gas Daily's California price and Gas Daily's Permian price. By [words, "Gas Daily" underlined, twice].
15	1	used gas price data from a trade publication other than GMR? [word, "GMR" underlined].
16	15	Monthly, by the monthly price basis differentials
16	48	**annual**~~monthly~~ gas consumption for California, taken from the
16	14	consumption for California, taken from the Natural Gas
16	15-22	~~Natural Gas Monthly~~ Natural Gas Monthly, by the **decline in the period average**~~monthly~~ price basis differentials ~~experienced since the PGT Expansion. I then took the average monthly cost to California due to the differentials and multiplied this number by twelve to arrive at the yearly cost. I repeated the foregoing steps for each of the three periods of time in the analysis (i.e., pre Kern River, Kern River to PGT Expansion, and PGT Expansion through the present)~~.
17	2-3	the PGT Expansion. Note that ~~in each case (Kern River and PGT Expansion),~~ I excluded the build-up of benefits that
27	15	Walsh's Exhibit No.____(NFW-19) **(reproduced in Exhibit No.___(BSA-16))**, but the causality is not reasonably
33	7	costs;" and (5) the **effect**~~fact that~~ the creation of a
43	21-22	Had you used a different publication from Inside FERC's Gas Market Report [words, "Inside FERC's Gas Market Report" underlined].

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generators, non-utility generators, as well as many industrial and commercial customers. The price that major buyers pay for physical gas supplies at the California border is reported by various trade press, including Inside FERC's Gas Market Report (GMR), Gas Daily, Natural Gas Week (NGW), and Natural Gas Intelligence (NGI). The physical market prices of gas in the region's representative producing basin are also reported by the same trade press for the same periods of time. Thus, one appropriate measure of gas cost benefits is the difference between GMR's price index for California and GMR's price index for the Permian Basin. Also appropriate would be the difference between Gas Daily's California price and Gas Daily's Permian price. By using the same publication's reported gas prices, we eliminate methodological differences with respect to data collection, processing and reporting, as they may exist from one trade publication to another.

Q. Why did you choose a Permian price index for comparison with California gas prices?

A. I did so because Permian is reflective of gas from the U.S. southwest states, which constitutes the major gas producing region for California. According to estimates of PG&E and Southern California Gas Company as reported in the 1994 California Gas Report, as documented in Exhibit No.____(BSA-4), approximately 66.2 percent of California's used gas price data from a trade publication other than GMR?

A. No, the results and conclusions would be the same. As a check, I replicated the analysis of Exhibit No.____(BSA-5), using data from NGI and NGW, rather than GMR. As can be seen in Exhibit No.____(BSA-8), the results conformed to those obtained using GMR.

Q. Could the results be explained by the weather?

A. No. In fact, we investigated whether the results were caused by weather. We found that they were not and that the price differences would have been even larger if we had normalized for weather.

Q. At what point did you measure the California border price?

A. At Topock, which is the delivery point at the Colorado River from El Paso and Transwestern into the facilities of Southern California Gas Company and PG&E.

Q. If your analysis had considered gas delivered by Transwestern, would the results have been the same?

A. Yes, they would have. The spot prices for gas on both Transwestern and El Paso are nearly identical, with the nearly perfect R^2 relationship of 0.989. The mean price for El Paso throughout the period was $1.66/MMBtu; the mean price for Transwestern was $1.65/MMBtu. Therefore, not only do the two pipelines' gas markets correlate almost perfectly, they have essentially the same values as well.

Q. If you had used the San Juan Basin price index instead of the Permian Basin price index, would the results have been the same?

A. Essentially, yes. As seen in Exhibit No.____(BSA-9), the step function is almost equally apparent using San Juan as the major supply basin, rather than the Permian Basin.

Q. In summary, what is the extent of the benefit which the PGT Expansion conferred on California gas users?

A. I conclude that California gas customers began receiving a benefit of approximately $382 million per year in the form of lower gas prices as a result of the completion of the PGT expansion system.

Q. How do you arrive at the foregoing estimate?

A. As seen in Exhibit No.____(BSA-10), I multiplied **annual**~~monthly~~ gas consumption for California, taken from the ~~Natural Gas Monthly~~ Natural Gas Monthly, by the **decline in the period average**~~monthly~~ price basis differentials ~~experienced since the PGT Expansion. I then took the average monthly cost to California due to the differentials~~ and multiplied this number by twelve to arrive at the yearly ~~cost. I repeated the foregoing steps for each of the three periods of time in the analysis (i.e., pre Kern River, Kern River to PGT Expansion, and PGT Expansion through the present)~~. The difference in the State's total gas cost before and after the Kern River opening is the benefit to gas consumers caused by Kern River. The difference in the

State's total gas cost due to differentials before and after the PGT Expansion is the benefit to gas consumers created by the PGT Expansion. Note that ~~in each case (Kern River and PGT Expansion),~~ I excluded the build-up of benefits that accrued during the transition period that followed each new capacity expansion, but, instead, developed a benefits estimate which is reflective of the steady-state for forecast purposes.

Q. How much of the foregoing benefits accrue to PG&E, and to PG&E's core markets?

A. PG&E's customers receives $162 million in gas cost benefit annually as a result of the PGT Expansion, and PG&E's core markets receive $54 million. I prepared this estimate based on each sub-market's share of state-wide gas volumes, as follows:

Table BSA-1

Market	Annual Volume (Bcf)	Percent of State	Benefit ($\$10^6$)	Impact of PGT Roll-In ($\$10^6$)	Net Benefit ($\$10^6$)
Statewide	2,043	100.00%	382	30	352
PG&E	864	42.29%	162	52	110
PG&E Core	290	14.19%	54	29	25

Sources: Natural Gas Monthly, 1994 California Gas Report; PGT response to EPNG-1 Data Request No. 9; Exhibit No.____(HTA-2)

Note that in the foregoing table, I have subtracted the

the so-called "stranded costs" are not new costs imposed on California, since the so-called "stranded costs" are just a subset of interstate pipeline charges that California entities have been paying for a long time. Ms. Walsh and Dr. Weisenmiller attribute much, if not all of these "costs" to the PGT Expansion. In fact, the value of capacity on El Paso in the capacity release market did decline after PGT's Expansion because that Expansion opened to California markets 766 MMcf per day of relatively low-cost gas which could not previously be delivered to the state, and buyers increased their purchases of the newly-available lower-cost alternative supplies, i.e., by filling the Expansion capacity, but not to the extent Ms. Walsh claims. The total decline in the value of pipeline capacity from the southwest is reasonably portrayed by the chart on page 8 of Ms. Walsh's Exhibit No.____(NFW-19) **(reproduced in Exhibit No.___(BSA-16))**, but the causality is not reasonably portrayed.

As seen in Column (17) of the chart in Exhibit No.____(BSA-16), the average difference between PG&E's demand charge obligation to El Paso for the capacity offered for release and the revenues received from replacement shippers (the "Remaining Obligation") in the three months before the PGT Expansion (i.e., from August 1993 through October 1993) was $4,046,000 per month, while the average exaggerated number ignores: (1) the usefulness of these contractual assets to PG&E or its customers; (2) any notion of whether these "stranded costs" become "stranded before or after the PGT Expansion (it is mostly before); (3) whether these "stranded costs" can be attributed to pipelines other than the PGT Expansion (some certainly can); (4) the extent to which Order No. 636 capacity release on PGT's pre-Expansion capacity contributed to these "stranded costs;" and (5) the **effect**~~fact that~~ the creation of a secondary market for capacity under Order No. 636 has had on the commoditization of pipeline capacity, enabling the value of the capacity to be identified and monetized. Still, on page 4 of Dr. Weisenmiller's Cross-Answering Testimony, we are then advised that his winning $500 million estimate of PG&E's so-called "stranded costs" is seriously understated because it excludes Southern California Gas Company. Overall, Dr. Weisenmiller's characterization of so-called "stranded costs" is meaningless and useless.

Q. Please summarize the information you believe the FERC should consider about the so-called "stranded costs" issue.

A. The FERC should ignore the contest among opposing witnesses to beef up the heftiest estimate of so-called "stranded costs." As Ms. Rosput discusses, so-called "stranded costs" are a red herring (Exhibit No.____(PGR-1)). However, should the Commission seek for any reason, to quantify the effect

Q. Does the increase in Seattle City Gate to Rockies basis that followed the PGT Expansion according to your Exhibit No.____(BSA-21) undermine your conclusion as to the existence of a benefit due to competition?

A. No, it does not. The increase in average Seattle to Rockies price basis in 1994 of $0.028 per MMBtu was minor compared to the decrease in Seattle to Sumas price basis of $0.113 per MMBtu over the same period of time. Moreover, consumers accessing Northwest Pipeline have the ability to shift their purchases between the Rocky Mountains and British Columbia (Sumas) if price conditions warrant.

Q. Could the benefit you calculated have resulted strictly from transportation discounting?

A. No. As was the case for the pipelines serving California from California's traditional Permian and San Juan supply basins, namely El Paso and Transwestern, Northwest's interruptible discounts in 1994 were generally the same as they were in 1993, as shown in Exhibit No.____(BSA-23). This leads me to believe that the average decline in basis of $0.0425 per MMBtu was more a result of intermarket competition, and cannot be attributed solely to transportation pricing.

Q. Had you used a different publication from Inside FERC's Gas Market Report to conduct your analysis, would your results have changed?