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THE PUBLIC UTILITIES COMMISSION has requested an advisory opinion, pursuant to Public Utilities Code section 854, on the following questions:

1. Will the proposed merger between Pacific Enterprises and Enova Corporation adversely affect competition?

2. What mitigation measures could be adopted to avoid any adverse effects on competition that do result?

CONCLUSIONS

1. The proposed acquisition between Pacific Enterprises and Enova Corporation should not by itself adversely affect competition in the markets for interstate gas or wholesale electricity.

2. The merger may eliminate the disciplining effect of San Diego Gas & Electric as a potential competitor in the partially regulated intrastate gas transmission market. We recommend that the Commission consider requiring the merged entity to auction offsetting volumes of transportation rights within that system.

ANALYSIS

The proposed merger of Pacific Enterprises and Enova Corporation is a response to the mandatory restructuring of the electric industry which began on January 1, 1998. Through their subsidiaries, Pacific is the leading southern California supplier of intrastate gas transmission services, Enova is an electric distributor and a relatively minor participant in the wholesale electricity market, and both firms distribute gas within their respective service areas. As regulated utilities doing substantial business within this state, the parties have submitted their application under Public Utility Code section 854. This memorandum responds to a Commission request for an opinion on the competitive effects of the transaction.

Challenges to the merger have primarily focused upon alleged effects in the markets for wholesale electricity, interstate gas and intrastate gas transmission. Through Southern California Gas Company (SoCalGas), Pacific provides gas transmission services to many of the gas-fired generation plants within southern California, including plants now owned by San Diego Gas and Electric (SDG&E) and Southern California Edison (Edison). Edison and others contend that the merged company will "leverage" its position in the gas transmission market to manipulate the price of electricity sold by these plants in the wholesale market. Intervenors also allege that the applicants will unfairly benefit in financial markets and that, by exercising options to purchase competing intrastate facilities, their alleged ability to manipulate electricity prices will be enhanced in the future.

We conclude that this merger will not adversely affect competition within either the wholesale electricity or interstate gas markets. Because gas-fired plants now owned by SDG&E will be subject to comprehensive price regulation, the merged entity will lack any incentive (or, usually, the ability) to manipulate wholesale electricity prices. Moreover, the wholesale electricity and interstate gas markets are already highly integrated, and comprise most of the western United States. Price data -- as opposed to theoretical models -- shows that the wholesale electricity market connects California with numerous out-of-state suppliers over a transmission system that has never reached capacity. These out-of-state suppliers, along with California generation plants outside the SoCalGas service area, would defeat any attempt by the merged entity to raise wholesale electricity prices above competitive levels. In any event, SoCalGas cannot significantly increase the costs of southern California gas-fired plants, whose gas prices are determined in the competitive interstate market and most of whose intrastate transportation rates are at their regulatory caps.

We also conclude that the merger of the utilities' procurement operations will not adversely affect competition in the interstate gas market and that the applicants are not actual potential competitors for retail electricity services. On the other hand, because the merger may eliminate the disciplining effect of SDG&E as a potential competitor in the partially regulated intrastate gas transmission market, we recommend that the Commission consider requiring SoCalGas to *auction* offsetting volumes of transportation rights within that system. Finally, because of the uncertain effects of electric industry restructuring, we also recommend that the Commission retain limited jurisdiction over this merger for the purpose of reexamining the question of whether the merged entity has used its intrastate gas transmission system for the purpose of manipulating the price of electricity it sells in the wholesale market.

I. PRIOR PROCEEDINGS AND THE NATURE OF THIS OPINION

A. Prior Proceedings

This merger would be completed by combining Enova and Pacific into NewCo, a holding company created for the purpose of consummating this transaction. **Footnote No. 1** NewCo Enova Sub would merge into Enova, with Enova as the surviving corporation. Likewise, NewCo Pacific Sub would merge into Pacific with Pacific as the surviving corporation. Enova and Pacific would be wholly-owned NewCo subsidiaries. Enova, Pacific, SDG&E, and SoCalGas would operate separately and under their existing names.

On June 25, 1997, the Federal Energy Regulatory Commission (FERC) conditionally approved the merger. **Footnote No. 2** In general, the conditions imposed by FERC would require SoCalGas to treat SDG&E and other affiliates "in the same way pipelines treat their gas marketing affiliates." **Footnote No. 3** The applicants subsequently incorporated those conditions, along with other proposed restrictions, within their merger application. **Footnote No. 4**

B. This Advisory Opinion

This is the fifth opinion letter submitted by this office under the 1989 amendments to Section 854. **Footnote No. 5** Public Utility Code section 854 refers to the opinion as advisory. **Footnote No. 6** Consequently this document does not control the PUC's finding under section 854, subdivision (b)(3). However, the Attorney General's advice is entitled to the weight commonly accorded an Attorney General's opinion (see, e.g., *Moore* v. *Panish* (1982) 32 Cal.3d 535, 544 ("Attorney General opinions are generally accorded great weight"); *Farron* v. *City and County of San Francisco*, (1989) 216 Cal.App.3d 1071).

II. THE APPLICANTS AND THE INTRASTATE GAS TRANSPORTATION AND ELECTRICITY SERVICES THEY PROVIDE

Pacific Enterprises and Enova Corporation currently compete on a very limited basis. SoCalGas purchases gas in the interstate market, which it distributes to its 4.7 million residential and other "core" customers in southern and central California. "Core" customers include residential and commercial customers without alternate fuel capability, whereas "non-core" customers are large commercial and industrial consumers that can buy gas from different sources. SoCalGas is the leading supplier of intrastate gas transmission and gas storage services for both "core" and "noncore" customers within southern California. Pacific Enterprises also sold electricity in the wholesale market through QF facilities, all of which were recently divested. **Footnote No. 7** In 1996, Pacific generated revenues of $1,613 million from its gas distribution operations and $778 million from intrastate gas transportation services provided to commercial/industrial and gas-fired generation plants.

SDG&E, which actively buys and sells power in the wholesale market, **Footnote No. 8** sells electricity to 1.2 million retail customers in San Diego and southern Orange Counties (including parts of the SoCalGas service area). SDG&E also purchases gas in the interstate market, **Footnote No. 9** which it distributes within its separate service areas. **Footnote No. 10** SDG&E provides no gas transmission services outside of San Diego County. **Footnote No. 11** In addition, an affiliate of Enova Corporation, Enova Energy, conducts extensive wholesale and retail energy marketing activities throughout California. In 1996, Enova generated revenues of $1,591 and $348 million from its electricity and gas distribution operations, respectively.

Applicants have formed a joint venture, Energy Pacific, to market gas, power and a "broad range of value-added energy management products and services." **Footnote No. 12** The applicants also recently purchased AIG Trading, a natural gas and electricity marketer and a trader in financial markets for electricity and gas contracts. **Footnote No. 13** Both of those companies are actively involved in the electricity and gas markets in California. This section discusses intrastate gas transmission services supplied by SoCalGas and SDG&E purchases and sales in the restructured electric industry. Interstate gas and electric services are discussed in Section III.

A. The Purpose of the Merger

The applicants claim that their merger will produce a firm with the necessary breadth and financial strength to compete with Edison, PG&E and out-of-state suppliers in the restructured electric industry mandated by AB 1890. As a result of that restructuring program, SDG&E and other California electric utilities will lose their exclusive "franchises" on January 1, 1998. The applicants contend that the merger will provide Enova, which is approximately one-fifth the size of Edison and PG&E, **Footnote No. 14** with "access to adequate quantities of capital on favorable terms." The parties also believe that the merged company will achieve certain efficiencies and will respond more effectively to customer demand for broader and more cost effective energy services.

B. SDG&E Market Power Mitigation under Electric Restructuring

Under industry restructuring, two separate central authorities, the Power Exchange (PX) and the Independent Service Operator (ISO), will coordinate all transactions between SDG&E and other California utilities. **Footnote No. 15** SDG&E currently purchases a majority of the electricity it sells to its retail customers. In 1995, for example, SDG&E obtained 61 percent of its power requirements from short-term Western States Coordinating Council (WSCC) purchases, 22 percent from fossil generation plants--including its own 1,973 MW capacity plants--located within the San Diego Basin, **Footnote No. 16** and the remaining 17 percent from the San Onofre Nuclear Generating Station (SONGS). **Footnote No. 17** In 1996, the peak load for the SDG&E system was 3,299 MW. **Footnote No. 18**

During a five year transition period beginning January 1, 1998, SDG&E and other investor owned utilities (IOUs) must purchase and sell all of their power through the PX, which will establish a single clearing price for all hourly transactions. **Footnote No. 19** Participating distribution companies and end users will submit "demand side" bids to the PX. **Footnote No. 20** Generation plants and marketers will simultaneously submit advance supply bids. **Footnote No. 21** The total capacity of WSCC members, including capacity divested from Edison and PG&E, **Footnote No. 22** which can bid into the PX exceeds 150,000 MW. **Footnote No. 23** From the resulting demand and supply schedules, the PX will establish **Footnote No. 24** the market "clearing price" governing all purchases and included sales. **Footnote No. 25**

Power produced by "must-take" and "must-run" resources will be priced separately. The output of must-run units -- the fossil generating plants used by the ISO to maintain system integrity **Footnote No. 26** -- will be sold at their variable operating costs. **Footnote No. 27** The ISO Governing Board "has chosen all of SDG&E's units for Must-Run status." **Footnote No. 28** Must-take resources, which include SONGS and other nuclear plants, qualifying facilities (QFs) and pre-existing power contracts, **Footnote No. 29** provide more than half of the electricity requirements of the California IOUs. **Footnote No. 30** A "performance incentive mechanism . . . will isolate SONGS revenue received by SDG&E from the PX price." **Footnote No. 31** Other nuclear power output prices will be regulated by the PUC, and existing contracts will determine the price of purchased power and QF output.

To preclude the exercise of any possible market power, SDG&E will bid the output of its gas-fired and other plants into the PX under ISO "Agreement B" **Footnote No. 32** during periods when those plants are not operated on a must-run basis. That agreement applies separate payment provisions to the two periods. As noted above, SDG&E will recover its variable costs during must-run periods. At other times, Agreement B requires the operator to return to the ISO "90 percent of any revenues earned in excess of the running costs." **Footnote No. 33** The remaining ten percent will apparently be applied to SDG&E stranded costs through the competitive transition charge (CTC) mechanism. **Footnote No. 34** On October 30, 1997, FERC concluded that this arrangement "adequately mitigate[s] [SDG&E's] generation market power for PX sales of energy." **Footnote No. 35**

In conjunction with the PX, the ISO will coordinate intrastate power flows and provide open access to the California transmission grid. **Footnote No. 36** On January 1, 1998, all participants will transfer operational control of their transmission facilities to the ISO. **Footnote No. 37** The state will initially be divided into "congestion zones" for northern and southern California, within each of which little or no congestion is expected. Users within the zones will pay a single transmission access charge based upon the revenue requirements of the owners of the transmission facilities. **Footnote No. 38** A bidding process, similar to that used by the PX, will establish usage charges for entities which transmit power over congested paths through or out of the ISO grid. **Footnote No. 39**

C. SoCalGas Intrastate Gas Transmission Services

SoCalGas carries gas to its "core" and "noncore" customers from delivery points for interstate pipelines or their intrastate extensions. When it created these customer classifications in 1986, the PUC required SoCalGas to offer "transportation only" services to its noncore customers, including generation plants owned by some of the intervenors in this proceeding. Since 1986, the ability of noncore customers to choose among gas producers and transportation services has been significantly expanded.

1. The SoCalGas Intrastate System

Five interstate pipelines carry natural gas to California: the Transwestern Pipeline Company ("Transwestern"); the El Paso Natural Gas Company ("El Paso"); the Pacific Gas Transmission Company ("PGT"), a PG&E subsidiary; the Kern River Transmission Company ("Kern River"); and the Mojave Pipeline Company ("Mojave"). At the Arizona-California border, SoCalGas receives gas from the Transwestern line at North Needles and from the El Paso line at Topock and Blythe. **Footnote No. 40** In the northern part of its service area, SoCalGas receives gas from PG&E at Kern River Station and Pisgah, **Footnote No. 41** and from the Kern River and Mojave lines at Wheeler Ridge and Hector Road. Footnote No. 42 The SoCalGas system is capable of receiving approximately 3.5 Bcf/d at these connection points. Footnote No. 43

The SoCalGas Acquisition Group purchases about 1000 MMcf/d, which is ultimately transported to core customers. Footnote No. 44 SoCalGas noncore transportation customers include Edison, members of SCUPP, SDG&E, the City of Long Beach, and various large commercial and industrial customers. Footnote No. 45 SoCalGas supplies 42 gas-fired generation plants, including plants owned by SDG&E, Edison, Imperial Irrigation District (IID) and SCUPP members. Footnote No. 46 These plants have a total generating capacity of 15,837 MW. Footnote No. 47 SoCalGas is the only intrastate gas pipeline to which SCUPP members can feasibly connect. Footnote No. 48

To coordinate deliveries to these customers and to preserve "system integrity," Footnote No. 49 SoCalGas calculates in advance of "flow day" Footnote No. 50 a system "window" from the difference between estimated overall next-day demand Footnote No. 51 and local Footnote No. 52 California gas production. Footnote No. 53 This "take away" capacity figure is then adjusted by anticipated injection or withdrawal volumes Footnote No. 54 for SoCalGas storage fields, Footnote No. 55 which according to Edison "are used to satisfy the majority -- approximately 57% -- of peak day demand." Footnote No. 56 Windows are also established at each of the individual receipt points. Footnote No. 57 SoCalGas uses a variety of procedures, including "custody cut" Footnote No. 58 and Rule No. 30 restrictions, Footnote No. 59 to achieve system balance when demand "nominations" for core and noncore customers exceed system or individual receipt point windows. Footnote No. 60

2. Transportation "Unbundling" and System Bypass

When the PUC "unbundled" transportation services in 1986, noncore customers were able to directly purchase commodity from wellhead producers at competitive prices and to make their own arrangements for the transport of that gas over interstate pipelines. In subsequent years, the Commission has also permitted the creation of a limited secondary market for intrastate transportation, even though it still prohibits "brokering on the intrastate system." Footnote No. 61 The GasSelect electronic bulletin board, "an interactive same-time Footnote No. 62 reservation and information system," Footnote No. 63 provides information within this secondary market about intrastate transportation transactions between SoCalGas and its affiliates. Footnote No. 64

Bypass opportunities for noncore customers have also been expanded. The Kern River and Mojave pipelines responded to these opportunities by extending their interstate systems across the California border into the SoCalGas service territory. Footnote No. 65 SoCalGas withdrew its initial opposition under 1989 agreements providing it with options to purchase in the year 2012 the California extensions of those two lines. Footnote No. 66 Since their completion in 1992, both systems have delivered gas to Enhanced Oil Recovery (EOR) and related cogeneration loads, and "to SoCalGas and PG&E for redelivery to other industrial and commercial loads." Footnote No. 67

This competition has induced SoCalGas to "provide discounted Footnote No. 68 transportation rates and associated cost saving to numerous customers [perhaps including SDG&E Footnote No. 69] on its system." Footnote No. 70 SoCalGas can provide such discounted service to noncore customers without obtaining prior CPUC approval. SoCalGas estimates that, since 1992, it has lost transportation volumes of 400 million cubic feet per day to competing gas pipelines. **Footnote No. 71** SoCalGas also claims that competition from out-of-state electric generation plants ("bypass by wire") has reduced the aggregate load of California gas-fired facilities by an additional 275 million cubic feet per day. **Footnote No. 72**

Along with federal deregulation efforts, these changes left SoCalGas and other utilities with contracts for interstate pipeline capacity that exceeded their market requirements. Accordingly, SoCalGas has since 1992 reduced its firm capacity on the El Paso pipeline from 1750 MMcf/d to 1150 MMcf/d and from 750 MMcf/d to 300 MMcf/d on the Transwestern system. **Footnote No. 73** To mitigate the resulting losses, the PUC has required customers to pay SoCalGas an ITCS (Interstate Transportation Cost Surcharge) **Footnote No. 74** to help recover certain fixed capacity costs. **Footnote No. 75**

III. INTERSTATE GAS AND WHOLESALE ELECTRICITY MARKETS AT THE CALIFORNIA BORDER

SoCalGas and California generation plants purchase the majority of their gas supplies from four producing basins in the western United States and Canada. **Footnote No. 76** Likewise, SDG&E purchases the majority of its electricity supplies from western United States and Canadian generation plants.

As a result of federal deregulatory efforts, these western United States gas and electricity markets are fully competitive. Both industries consist of three vertically-related stages: production, transmission, and distribution. **Footnote No. 77** Production and interstate transmission services within both of those markets are highly integrated at the California border. Moreover, California wholesale electricity transactions, which SDG&E and other utilities now make throughout the western United States, will remain integrated with the interstate market after the January 1, 1998 restructuring.

A. Federal Deregulation and the Interstate Gas Market

Federal deregulation of the gas market has created a network of transmission suppliers connecting purchasers at the wholesale level with middlemen and well operators at the production level. Prior to these efforts, each interstate "pipeline would purchase natural gas from producers, transport it largely along their own proprietary pipeline system, and resell the rebundled product to local distribution companies (LDCs) and other large customers." This institutional structure meant that "each producer could sell gas to a limited number of buyers" and that "LDCs and large end users had limited options in terms of the number of pipeline companies from which they could purchase gas." **Footnote No. 78** As a result of FERC's deregulatory policies, "an active and viable spot market has developed for gas." **Footnote No. 79**

FERC transformed the gas industry by providing open access to interstate pipelines, removing all controls over the wellhead price of natural gas, **Footnote No. 80** and establishing secondary markets for storage and pipeline capacity. **Footnote No. 81** Pipelines now compete to provide transportation services with each other and with middlemen and with other owners of capacity rights. Wellhead deregulation has simultaneously generated competition between producers in different basins. **Footnote No. 82** Because end users attempt to minimize their "delivered prices," **Footnote No. 83** competitive forces have also linked the production and transmission markets.

FERC's open access policies, instituted in Orders 436 **Footnote No. 84** and 636, required that interstate pipelines separate gas sales from transportation services, **Footnote No. 85** allowing users to enter into direct agreements with producers at the wellhead and arrange transportation in a separate transaction. Orders 436 and 636 also created a "secondary transportation market" for natural gas **Footnote No. 86** by allowing "holders of unutilized firm capacity [to resell] them in competition with any capacity offered directly by the pipeline." **Footnote No. 87** Previously, shippers were only able to purchase capacity rights directly from pipelines. **Footnote No. 88** Under Order 636, shippers who wish to sell (i.e. "release") their firm capacity rights must first offer **Footnote No. 89** those rights on the pipeline's electronic bulletin boards ("EBB") **Footnote No. 90**, which carry "information about available and consummated capacity release transactions." **Footnote No. 91**

These policies have allowed producers in Canada, the Rocky Mountains, the San Juan and Permian Basins, as well as other regions to compete for sales throughout California. The five pipelines which deliver this gas have an aggregate capacity of 7,130 MMcf per day. **Footnote No. 92** The 3.5 Bcf/d El Paso Natural Gas Company and the 1.1 Bcf/d Transwestern Pipeline Company lines are the primary links between the southern California border and producers in the San Juan and Permian basins. **Footnote No. 93** Pacific Gas Transmission Company ("PGT"), a PG&E subsidiary, transports gas from Canada to the California border on its own 1.89 Bcf/d pipeline. Coupled with downstream pipeline system operated by SoCalGas and SDG&E, PG&E can serve end users in most of California. **Footnote No. 94** As noted in Section II, the 770 MMcf/d Kern River line, which originates in the Rocky Mountain Basin, and the 400 MMcf/d Mojave pipelines began commercial operations in 1992.

In this deregulated interstate market, both purchasers and suppliers have various alternatives as they seek to minimize the overall cost of purchasing, transporting and storing gas. **Footnote No. 95** Thus, many EOR customers, who previously transported gas from Southwest fields over the El Paso or Transwestern lines, substituted when they found it more economical to transport Rocky Mountain gas over the Kern River or Mojave lines. **Footnote No. 96** In other instances, customers have substituted by transporting over the same pipeline to California gas purchased in entirely different basins. **Footnote No. 97** Customers committed to a particular supply source can also substitute between firm contracts and capacity released in the secondary market. **Footnote No. 98** Commodity and transportation markets are also linked, **Footnote No. 99** as producers in the San Juan Basin demonstrated between November 1990 and April 1992 and again between March 1995 and December 1996 by reducing commodity prices to offset the temporarily increased cost of transporting gas over the constrained El Paso line. **Footnote No. 100**

B. Federal Wholesale Electricity Deregulation

Federal deregulation has had similar effects on wholesale electricity prices at California delivery points. Congress initiated deregulation of the electricity industry by first allowing independent power producers and then utility affiliates to offer wholesale electricity at "market-based prices." **Footnote No. 101** Through Order 888 and earlier mandates, **Footnote No. 102** FERC simultaneously encouraged open access and other "wheeling" transactions between non-contiguous buyers and sellers. **Footnote No. 103** By 1993, the "wholesale sector of the U.S. electricity industry [had] been transformed from an industry dominated by ineffectively regulated, inefficient monopolists to an industry that is increasingly dominated by robust competition." **Footnote No. 104**

Edison, SDG&E and PG&E actively participate in one of the most integrated of these wholesale electricity markets, the WSCC, which includes "fifteen states in the western United States and part of Canada." **Footnote No. 105** The WSCC "is a highly complex network that interconnects the entire western United States from Canada to Mexico and east as far as Montana, Utah, and New Mexico." **Footnote No. 106** WSCC members include Bonneville Power & Light, British Columbia Hydro, Los Angeles DWP, SMUD, and the Salt River Project. The aggregate capacity of WSCC members, which arrange wholesale electricity transactions through the Western States Power Pool ("WSPP") or through separate bilateral transactions, **Footnote No. 107** exceeds 150,000 MW. **Footnote No. 108**

As a result of industry deregulation, suppliers can now sell to any purchaser on the grid. **Footnote No. 109** In fact, the availability of displacement contracts and the physics of electricity transmission has rendered irrelevant transmission constraints between any two points within the network. **Footnote No. 110** The existence of "loop flows," **Footnote No. 111** in particular, means that power in a network "moves across many parallel lines in often circuitous routes." **Footnote No. 112** Likewise, suppliers facing transmission constraints can indirectly meet their contractual obligations by entering into offsetting displacement contracts with sellers located on unconstrained links to the delivery point. **Footnote No. 113** Accordingly, sellers must now compete for any sale with utility affiliates, independent power producers and power marketers.

The resulting competition has dramatically increased the integration and efficiency of the wholesale electricity market. The WSCC, in particular, had actually become a highly integrated market even before FERC issued Order 888. **Footnote No. 114** Using data from 1994-1996 transactions, De Vany and Walls have shown that the implicit delivered price of wholesale electricity is *identical* throughout the western United States during most hours of the day. **Footnote No. 115** The market is so highly integrated, in fact, that arbitrage opportunities are virtually nonexistent between supply points during both "peak" and "off-peak" hours. Thus, De Vany and Walls found that the California-Oregon Border ("COB"), Northern California, Palo Verde and Southern California were cointegrated **Footnote No. 116** with all ten of the other major WSCC delivery points examined during off-peak hours; and with 9, 9, 10, and 9 of the other 10 delivery points, respectively, during peak hours. Order 888 has undoubtedly strengthened these results. **Footnote No. 117**

C. The PX and the Western United States Wholesale Market

ISO and PX rules will allow out-of-state utilities to bid into the PX. **Footnote No. 118** Those out-of-state suppliers will compete for sales of wholesale electricity sold through the Power Exchange, and their participation will equalize prices between the Exchange and the larger market. Any differences between the Power Exchange price and the prevailing wholesale price would also be disciplined by marketers and California utility customers who would bypass the PX and arrange direct purchases from out-of-state sources. **Footnote No. 119**

As noted above, loop flows maintain system viability when constraints arise over individual transmission paths. The "contract path" between a generating plant and a customer is a "fiction," which "may and often does diverge" from the actual flow of power. **Footnote No. 120** Thus, the physics of electrical networks would allow southern California customers to withdraw from the WSCC transmission grid power simultaneously generated by BPA, even if a link in the most direct transmission route between the two parties (e.g., Path 15) were at capacity. For that reason, the precise capacity of any single link between California and other WSCC members is not relevant to this proceeding. **Footnote No. 121**

Price data -- which provides the best measure of market performance -- confirms the implications of engineering data which show that California has never been isolated from the rest of the WSCC. **Footnote No. 122** During off-peak hours, the implicit "shadow" price for transmitting electricity between the four major California delivery points at off-peak hours is virtually zero, **Footnote No. 123** reflecting the system's low variable supply costs. Implicit peak hour transmission rates are higher, but wholesale electricity prices at the four delivery points during those times remain cointegrated within arbitrage bounds. **Footnote No. 124** These data are inconsistent with the fragmented transmission system and isolated wholesale markets alleged by some intervenors.

IV. THE RELEVANT MARKETS

The traditional antitrust model assesses the competitive effects of a merger within a "relevant market," which generally exhibits both product and geographic dimensions. The relevant product refers to the "horizontal" range of products or services that are or could be easily be made relatively interchangeable, so that pricing decisions by one firm are influenced by the range of alternative supplies available to the purchaser. The substitutes comprising the product market can be differentiated, at least to some extent. Thus, local telephone calls within the same exchange between A and B and between C and D are not identical services, but they are still in the same product market because they are such close substitutes.

The relevant product also has a vertical dimension. In most antitrust cases, there is a "range of possible markets of varying breadth." **Footnote No. 125** In theory, the horizontal and vertical dimensions of the relevant market are "immaterial." **Footnote No. 126** In fact, however, empirical limitations require a "noticeable 'gap in the chain'" of substitutes and complements. **Footnote No. 127** For example, it would usually be misleading to define separate product markets for left and right shoes or, because they are so strongly linked, for ski boots and ski bindings. **Footnote No. 128** More generally, the relevant product is defined by including the good which is immediately in question along with all other substitutes and complements which significantly affect the ability of the supplier to raise price above marginal cost.

Similar considerations govern the delineation of the relevant geographic market. The relevant geographic market is defined as the area in which sellers compete and in which buyers can practicably turn for supply. **Footnote No. 129** In any market, including interstate gas or wholesale electricity networks, the relevant geographic market will include all supplies whose prices remain closely linked, after transportation and other transaction costs are accounted for. Thus, distant seller A and local seller B are in the same market if the price at B equals the price at A plus the cost of transportation between the two points. More generally, two locations are in the same market if the differential between their (possibly independently varying) prices remains "less than the potential wedge created by arbitrage costs." **Footnote No. 130** Accordingly, "[p]rice relationships are clearly the best single guide to geographic market definition." **Footnote No. 131**

A. The Relevant Interstate Gas Market

For purposes of analyzing this merger, a relevant market can be defined as gas *delivered* at interstate receipt points by pipelines from the San Juan Basin, the Permian Basin, and basins in the Rocky Mountains and Canada. **Footnote No. 132** In a gas network, the ability of a customer (like SoCalGas) to deviate rates from competitive levels is determined by conditions at the wellhead, within the network itself, and at the ultimate delivery points. As noted above, users base their purchasing decision upon the overall delivered cost of the commodity, not the price at a particular wellhead or the cost of transmission over a single line. Prices are inextricably linked between basins, between pipelines, between firm and interruptible capacity on each line, **Footnote No. 133** and across these various service levels. **Footnote No. 134** The most limited product market providing a "gap" in this "chain" of complements is delivered interstate gas.

The geographical extent of this market includes at least deliveries from the four basin area. **Footnote No. 135** In 1995, total average production by these basins was 24,000 MMcf/d. **Footnote No. 136** Estimated peak day supplies to California are 3,536 MMcf/d. **Footnote No. 137** Because gas deliveries throughout the network are close substitutes, after transportation is accounted for, the geographic market is broader than gas deliveries to southern California customers. **Footnote No. 138** Similarly, the relevant product and geographic market is broader than capacity rights on the El Paso line between the San Juan basin and the California border. **Footnote No. 139**

Competition within this market is intense. The ability of a firm to raise prices above competitive levels is "commonly" shown with circumstantial evidence of industry concentration, **Footnote No. 140** entry barriers, and the short-run ability of existing competitors to increase their output. **Footnote No. 141** The courts also recognize the use of "direct evidence" to resolve market power questions. **Footnote No. 142** In the relevant interstate gas market, there are many buyers and sellers at the wellhead level, numerous holders of capacity rights competing with pipeline owners for transportation services, and strong price interactions between those levels. Moreover, "direct" evidence shows that prices at delivery points within the four basin area remain cointegrated within arbitrage bounds.

B. The Relevant Wholesale Electricity Market

A relevant market also exists for wholesale electricity delivered throughout the WSCC. Like their counterparts in the natural gas industry, customers purchase wholesale electricity as the "delivered" combination of generation and transmission services. **Footnote No. 143** Thus, the relevant market includes all suppliers whose combined "netback" and transportation costs would be competitive at California delivery points. **Footnote No. 144** The relevant geographic market is the WSCC because that is "the region from which generators will be able to bid power into the Power Exchange." **Footnote No. 145**

The relevant product market includes "all" effectively unregulated delivered electricity which can compete in the Power Exchange for residual wholesale electricity demand. **Footnote No. 146** Within the WSCC, the total capacity of competitive gas-fired, hydro, and coal plants exceeds 150,000 MW. These resources will compete for the demand remaining in the PX after sales of price-regulated must-run and must-take capacity are completed. As in the gas industry, there are numerous buyers and sellers in the wholesale electricity market, strong interactions between generation and transmission prices, and highly cointegrated prices at delivery points.

1. Alleged "Swing Capacity" Markets

The relevant product market for wholesale electricity cannot be meaningfully limited to "swing capacity" producers. Edison and other intervenors implicitly allege a product market consisting of generation with "full load marginal costs" **Footnote No. 147** within some range **Footnote No. 148** of the variable costs of producing electricity on Edison and other WSCC gas-fired plants. Intervenors contend that gas-fired plants with their relatively high production costs will be the only firms bidding at or near the "clearing prices" established by the Power Exchange. This proposed market, however, excludes Bonneville Power and other "inframarginal" suppliers located throughout the WSCC **Footnote No. 149** that are equally likely to establish the clearing price. **Footnote No. 150**

Intervenors exclude these other generation sources by implicitly assuming that out-of-state participants do not incur opportunity costs. **Footnote No. 151** Theoretically, PX participants will offer wholesale electricity at their marginal supply costs, including fuel and other variable production expenses. **Footnote No. 152** In addition, however, the relevant economic cost to out-of-state sellers **Footnote No. 153** will include returns foregone by selling to the Power Exchange instead of other western United States buyers. **Footnote No. 154** The existence of these opportunity costs explains why gas is not "the" marginal fuel, **Footnote No. 155** why out-of-state suppliers will equalize the PX and prevailing WSCC prices **Footnote No. 156** and, at least in part, why gas and electricity prices are weakly correlated in southern California. **Footnote No. 157** Their existence also means that the relevant product market includes the output of "inframarginal," out-of-state suppliers. **Footnote No. 158**

2. The Temporal Dimension

Similarly, the relevant market is not time-sensitive. A relevant market includes all firms which would respond to a hypothetical "small but significant and nontransitory" price increase. **Footnote No. 159** These firms include plants which are already "committed" to the market, but which make no contemporaneous sales. Accordingly, the relevant wholesale electricity market during peak periods includes all out-of-state WSCC suppliers.

As discussed above, WSCC suppliers can sell electricity throughout the grid during both peak and off-peak hours. **Footnote No. 160** Some intervenors have suggested that the relevant market will be limited during peak hours. **Footnote No. 161** It is true that during those periods, supply costs increase as some firms begin to reach capacity and (in some cases) as individual transmission paths become congested. These transitory, geographically dispersed costs increase price volatility. Even so, there is no evidence that, during peak periods, any WSCC firms withdraw from the market or that any out-of-state suppliers will be systematically excluded from the PX. In fact, price data shows that even before FERC issued Order 888 the major California delivery points were highly cointegrated during peak periods with the rest of the WSCC.

C. The Relevant Intrastate Gas Transportation Market

Although the applicants and many intervenors combine it with the interstate gas market, a separate relevant market can be defined for intrastate gas transportation and storage services within southern California. Ten years ago, SoCalGas and PG&E were the principal suppliers of these services. Since the completion of their intrastate extensions in 1992, Kern River and Mojave pipelines have also competed for transportation services to EOR and related cogeneration loads. Private pipelines provide additional competition.

Despite this recent competition, SoCalGas has maintained significant market power over these services. SoCalGas controls most of the intrastate capacity within southern California, including all transportation facilities located within Los Angeles, Orange and Riverside Counties. **Footnote No. 162** Moreover, as the extended Kern River and Mojave pipeline application process demonstrated, potential suppliers face substantial regulatory entry barriers. A controlling market position reinforced by high regulatory barriers to entry is strong evidence of market power. **Footnote No. 163** SoCalGas also price discriminates between transportation customers, and can sometimes discount without Commission approval. **Footnote No. 164** The ability to persistently price discriminate between similarly situated customers also implies that a seller possesses market power. **Footnote No. 165**

V. THE COMPETITIVE EFFECTS

Mergers are generally categorized as "horizontal," "vertical," or "conglomerate." The competitive effects of a merger are assessed by first defining the relevant markets and then determining whether the merged entity will have an enhanced ability to profitably skew price or output from competitive levels. **Footnote No. 166** Under the DOJ/FTC Guidelines, the effects of a "horizontal" merger depend upon several related factors, including changes in concentration levels, entry conditions, and efficiency enhancements. The government's vertical merger guidelines "recognize only three possible anticompetitive effects: that vertical mergers might create entry barriers, facilitate horizontal coordination, or allow a regulated firm to evade rate regulation." **Footnote No. 167** A failure to properly define the relevant markets is fatal to a plaintiff's *prima facie* case. **Footnote No. 168** A plaintiff must also demonstrate "probabilities"--not "ephemeral possibilities"--of anticompetitive effects within those markets. **Footnote No. 169**

A. The Vertical Integration of SoCalGas Intrastate Gas Transmission and SDG&E Wholesale Electricity Operations

Although this merger has some horizontal features, the primary link between the applicants is the gas transportation services SoCalGas provides to SDG&E. Those transportation services are an important component in the cost of generating electricity to SDG&E and other gas-fired plants in southern California. Vertical integrations do not, however, "automatically have an anticompetitive effect." **Footnote No. 170** This is because, unlike horizontal consolidations, vertical mergers do not eliminate competitors from the market. **Footnote No. 171** The vertical integration resulting from this merger, in particular, will not adversely affect competition in the wholesale electricity market because Agreement B negates any incentive of SDG&E (or the merged entity) to manipulate PX prices.

Even without the restrictions of Agreement B, however, SoCalGas could not significantly increase the costs of SDG&E's southern California competitors, whose gas prices are determined in the competitive interstate market and most of whose intrastate transportation rates are already at their regulatory caps. (Their current transportation rates are binding because the Commission prohibits SoCalGas from raising intrastate rates above existing tariff levels, which SoCalGas has discounted for only a small minority of the plants it serves. **Footnote No. 171.1**) Moreover, out-of-state suppliers would defeat any attempt by the merged entity to manipulate the price of wholesale electricity sold in southern California. **Footnote No. 172** The total capacity of plants supplied by SoCalGas is 15,837 MW. These plants will compete for end-users who can purchase electricity through the PX or through "direct access" agreements, with aggregate WSCC, out-of-state capacity exceeding 100,000 MW. **Footnote No. 173** Because out-of-state suppliers account for their opportunity costs **Footnote No. 174** and because of the absence of entry barriers faced by out-of-state suppliers wishing to make such sales, the resulting PX price will equal the prevailing WSCC spot price. **Footnote No. 174.1** Price data -- as opposed to simulation models -- demonstrate that WSCC prices are competitively determined. **Footnote No. 174.2** Neither SoCalGas nor the merged entity will have the ability to profitably deviate prices from competitive levels within that market.

1. The Intervenors' Vertical Integration Models

Intervenors have failed to demonstrate with "probabilities" that the integration of these vertically-related operations will have adverse competitive effects in any relevant market. Relying upon an engineering simulation instead of price data, **Footnote No. 175** the Edison "swing capacity model" discussed above ignores opportunity costs incurred by low cost producers and fails to define a cognizable relevant market. Similarly, SCUPP cites a vertical integration model which assumes that inputs are consumed only by suppliers in the endproduct market. **Footnote No. 176** That assumption does not hold in this case, where core and other noncore customers consume the vast majority of the gas transportation input gas-fired plants used to generate the wholesale electricity endproduct. Because both models assume that all suppliers employ the same technology to produce the endproduct, they also fail to account for other sources of competition in the wholesale market (*e.g.*, hydro and coal generation plants). **Footnote No. 177** Finally, and most important, neither model reflects the incentives of suppliers offering a price-regulated output, such as electricity sold by the merged entity under Agreement B.

2. Futures Markets

Edison, SCUPP and other intervenors also allege that the merged entity could "unfairly benefit" from vertical integration by manipulating wholesale electricity prices after it purchased contracts in the futures markets. Footnote No. 178 Thus, they contend, the merged entity would essentially trade on "inside" information. Footnote No. 179 As before, however, the merged entity would still be unable to manipulate wholesale prices and the merger would not enhance any existing ability of SoCalGas to profit in the futures markets. Footnote No. 180 Moreover, adverse effects upon competition within the futures markets -- which are characterized by their liquidity and ease of entry and exit Footnote No. 181 -- are extremely unlikely. Footnote No. 182 In any event, the hypothetical conduct would be unlawful under the Commodity Futures Trading Commission Act.

3. The Kern River and Mojave Pipeline Purchase Options

Kern River claims that the merged entity can extract increased supracompetitive profits in the wholesale electricity market by exercising its options to purchase in 2012 the California operations of the Kern River and Mojave pipelines. Footnote No. 183 This theory, which relies upon the swing capacity model, again overstates the significance of gas-fired generation and ignores the ability of an independent SoCalGas to obtain available supracompetitive profits. Footnote No. 184

Kern River also ignores the competitive nature of the purchase options, whose effects should be assessed from the perspective of the original settlement agreements. Economic efficiency considerations require courts to establish rights and obligations "*ex ante*;" i.e., on the date on which a crucial choice was made. Footnote No. 185 In 1987, SoCalGas and PG&E dominated transportation service markets in southern California. The purchase options, which the applicants contend were integral to the settlements between the parties, permit Kern River and Mojave to compete for those services from 1987 to 2012. If the parties had not settled their dispute, entry by those two pipelines would have been delayed and the subsequent competition they furnished would have been reduced. Abrogating the purchase options now would reduce incentives of other firms to enter into similar pro-competitive settlements in the future.

In addition, the year 2012 effective date allows purchasers and alternative suppliers a substantial period in which to respond the possible exercise of these options. Footnote No. 186 In any event, predictions about competitive effects 15 years into the future are highly speculative, particularly when they concern markets as dynamic as the rapidly changing gas industry. Footnote No. 187 We conclude that the purchase options, which contemplated increased competition within the intrastate market and which will not endow the surviving entity with additional market power, should not be abrogated by the merger.

4. The Applicants' "Remedial Measures"

Although this vertical integration does not "create" market power, it could alter the manner in which SoCalGas exercises its existing market power over intrastate transportation services. SoCalGas now exercises market power by discriminating in the price of services charged to gas-fired generation plants and other potential "bypass" customers. The merger will not provide new opportunities for profitable price or non-price Footnote No. 188 discrimination. We are also not aware of any evidence that the merged entity would use its market power to require simultaneous competitive entry into the gas and electricity markets or to facilitate coordination between SDG&E and other WSCC suppliers.

In fact, the remedial conditions proposed by the applicants will reduce the ability of the merged entity to engage in either price or non-price discrimination. Those proposed conditions expand FERC's requirement that Order 497 govern intrastate transactions between SoCalGas and SDG&E and other marketing affiliates. Order 497 generally requires interstate gas pipelines to treat their marketing and other affiliates and "similarly situated persons" on a non-discriminatory basis. Here, the applicants will retain their ability to price discriminate, but they have agreed to submit any planned discounts to the Commission for approval. In addition, they have agreed to refrain from discriminating in the provision of various types of services, including: the application of tariff provisions; transportation scheduling, balancing, storage, or curtailments; the processing of transportation requests; the disclosure of transportation information; and the offering of intrastate transportation discounts. **Footnote No. 189**

B. Horizontal Effects in the Intrastate Gas Transportation, "Gas Procurement" and Retail Gas Markets

The principal horizontal feature of this merger is the consolidated ownership of the applicants' gas procurement functions. **Footnote No. 190** Both of the applicants purchase gas in the interstate market for their core and some of their noncore customers and SDG&E makes significant purchases for its electricity generation plants. In 1996, SoCalGas and SDG&E gas purchases averaged 963 **Footnote No. 191** and 255 **Footnote No. 192** MMcf/d, respectively, while total production in the relevant interstate market averaged 24,000 MMcf/d. **Footnote No. 193** Thus, SoCalGas and the merged entity would account for approximately four and five percent, respectively, of purchases within the unconcentrated four basin gas market. We assume for purposes of analyzing this merger that SoCalGas is among the largest purchasers in the western United States. Following the Guidelines, we conclude from this assumed distribution of buyers that the merger of the two companies will have an insignificant effect upon competition in the interstate gas market. **Footnote No. 194**

The merger will also combine the two companies' partially deregulated non-core gas retailing functions. **Footnote No. 195** Although both applicants currently distribute gas to non-core customers, PUC rules significantly restrict the ability of SoCalGas to compete for such sales within its service area. **Footnote No. 196** Moreover, neither firm has made non-core sales outside its service area. **Footnote No. 197** In 1996, total non-core sales in southern California averaged 1821 MMcf/d. **Footnote No. 198** SoCalGas and SDG&E sales to non-core customers during that year averaged 58 and 144 MMcf/d, respectively. **Footnote No. 199** We conclude that the consolidation of these non-competing, relatively limited operations will not adversely affect competition for non-core retail services.

C. Potential Competition for Intrastate Gas Transportation and Electric Retail Services

This merger may eliminate SDG&E as a limited potential competitor in the market for intrastate gas transportation services. The demand for intrastate transportation in southern California is approximately 1 Bcf per day for SoCalGas core customers, between 125 and 300 MMcf per day for SDG&E, **Footnote No. 200** and approximately 1 Bcf per day for other noncore customers. The Project Vecinos agreement between the applicants and other evidence suggests, although not conclusively, that the threat of independent entry by SDG&E has provided some discipline to this less than fully competitive, high-entry-barrier market. We recommend that the Commission consider requiring SoCalGas to *auction* a volume of transmission rights over its system equal to the average SDG&E load.

The courts recognize two theories under which a merger between potential competitors may be challenged. The actual potential competition doctrine -- which is so speculative that it has never provided the basis for a successful challenge **Footnote No. 201** -- applies if the acquiring firm would have "probably" entered a concentrated market, thereby providing significant procompetitive effects. **Footnote No. 202** SDG&E may present a "threat of competitive entry by a bypass pipeline" and it may be an "attractive anchor customer" for pipeline construction "within" California. **Footnote No. 203** The courts, however, require showings of an intent to enter **Footnote No. 204** that go beyond evidence of generalized abilities and incentives. To avoid speculation, **Footnote No. 205** they also require a showing that entry will occur, not in the "reasonably foreseeable" future, but in the near future. **Footnote No. 206** We are not aware of any evidence that SDG&E had current or even reasonably contemporaneous plans to enter the gas transportation market.

1. The Perceived Potential Competition Doctrine

A merger may also be challenged if the acquiring firm is a "perceived potential entrant." This doctrine applies if the acquiring firm is "(1) perceived by existing firms as a potential independent entrant and (2) has exercised a tempering impact on the competitive conduct of existing sellers." **Footnote No. 207** In this case, SDG&E may have tempered the pricing of intrastate transportation services by threatening to bypass the SoCalGas system. Thus, in 1988, SDG&E considered building a pipeline to directly interconnect with the El Paso system. **Footnote No. 208** SDG&E considered at least two other bypass proposals during the next six years. **Footnote No. 209** Finally, in 1994, the parties entered into their Project Vecinos Revenue Sharing Agreement, where SoCalGas agreed to reduce transportation rates by an amount equal to: "the potential benefits that SDG&E would have received had it partially or totally bypassed SoCalGas by utilizing transportation services from a pipeline constructed in Baja California." **Footnote No. 210**

Despite this tempering effect, it is unclear if SDG&E is a current entry threat or if the Kern River pipeline and other suppliers view SDG&E as a potential entrant to the intrastate market. Because the Revenue Sharing Agreement remained confidential until recently, **Footnote No. 211** these other suppliers may not have recognized that SDG&E was considering bypass alternatives. Similarly, because SDG&E would have to build dedicated facilities to bypass SoCalGas, SDG&E entry or withdrawal may not affect price or output levels elsewhere in the market. More important, SDG&E may not still be a potential *supplier* of intrastate services. Although SDG&E would constitute a valuable "anchor tenant," **Footnote No. 212** the perceived potential competition doctrine applies to suppliers, not customers, which have the ability to compete with their merging partners. Unfortunately, the record fails to clarify these issues.

If the Commission does conclude that SDG&E is a significant potential competitor, we recommend that it require the merged entity to auction transmission rights over the SoCalGas system equal in volume to the average SDG&E load which will be withdrawn from the intrastate market. Following SCUPP, we suggest that buyers of those rights obtain undivided interests based on contract paths "from an established point of receipt to an established point of delivery." **Footnote No. 213** Those auctioned rights will constitute an alternative source of intrastate transportation, thereby offsetting the loss of SDG&E as a potential competitor. We propose an auction, with a long run marginal cost (LRMC) minimum bid, because it will ensure that the highest valued users receive these rights and because it will help reimburse SoCalGas for losses in the value of its system. Finally, because the competitive effects of SDG&E withdrawal from the intrastate market appears somewhat isolated, we suggest that the Commission establish this auction in separate proceedings following the completion of this merger.

2. The Retail Electric Services Market

IID alleges that SoCalGas is a potential competitor for retail electric sales within its gas distribution area. **Footnote No. 214** For the actual potential competition theory to apply, entry must have a deconcentrating or other significant procompetitive effect. This predicate effect will not exist "if there are numerous potential competitors," because the elimination of one of many "would not be significant." **Footnote No. 215**

As the applicants demonstrate, however, Edison and the Los Angeles Department of Water & Power already provide retail services within that region and 92 other companies, including eight of the leading firms in the industry, have already registered as Energy Service Providers with the Commission. **Footnote No. 216** Furthermore, SoCalGas has no competitive retail affiliates and limited experience within the electricity industry. **Footnote No. 217** There is also no evidence that Pacific had "actual" plans to provide such services or that Pacific's entry would have had significant procompetitive effects in any retail electricity markets. We conclude that the elimination of SoCalGas as a potential supplier would not have a significant effect upon competition in any California retail electricity market.

VI. RETENTION OF JURISDICTION

This office recognizes the uncertainty of the transition to the restructured system of wholesale electricity sales and transmission that will go into effect on January 1, 1998. Although we believe it is unlikely, we acknowledge the *possibility* that out-of-state sellers will fail to discipline the pricing of electricity sold by the merged entity. We do expect, however, that SoCalGas will continue to provide intrastate transportation services to the vast majority of gas-fired generation plants within southern California. In the unlikely event that the merged entity can manipulate the PX price, plants supplied by the Kern River and Mojave pipelines and plants subject to "take-or-pay" contracts may provide valuable competition in the restructured market. Accordingly, we recommend that the PUC, during its continuing review of the competitiveness of the wholesale market, specifically examine the pricing practices of the merged entity and the relationship between those practices and the operation of the SoCalGas intrastate transportation system. Thus, we recommend that the Commission consider retaining jurisdiction over this merger for a period of two years for the purpose of reexamining the limited questions of whether: (1) the merged entity has used its intrastate system to manipulate the price of electricity it sells in the wholesale market; and (2) whether abrogating the Kern River and Mojave pipeline options and the take-or-pay options would limit the ability of the merged entity to engage in such practices.

CONCLUSION

The only difficult factual issue raised by this merger is whether the applicants are potential competitors in the intrastate gas transportation market. The merger has no adverse "horizontal" effects because competition between the applicants is limited to such areas as the vast interstate gas market and non-core gas retailing. Vertical effects are also negligible because wholesale electricity offered by the merged entity will be subject to the constraints of comprehensive price regulation mandated by ISO Agreement B and because SoCalGas cannot significantly increase either the gas prices or the transportation rates paid by southern California gas-fired plants. In addition, out-of-state WSCC sellers, which are highly integrated with southern California during both peak and off-peak hours, would defeat any attempt by the merged entity to manipulate wholesale electricity prices. Edison's swing capacity model comes to an opposite conclusion by overlooking the fundamental concept of opportunity costs.

Some evidence does suggest that SDG&E is a potential supplier of intrastate gas transportation services. If the Commission finds that evidence persuasive, we recommend that it consider, in proceedings subsequent to the completion of this merger, requiring SoCalGas to auction a volume of intrastate transmission rights equal to the SDG&E load which will be withdrawn from the market by this merger. This remedy would introduce competition into the intrastate market, thereby offsetting any adverse effect of the merger and reducing incentives to construct duplicative, "uneconomic bypass" facilities. Finally, we recommend that the Commission retain limited jurisdiction over this matter for a period of two years during which it can review whether the merged entity uses its intrastate system to manipulate the price of electricity it sells in the wholesale market.

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Footnote No. 1
Application at 26.
Footnote No. 2 *See San Diego Gas & Electric Co.*, 79 FERC par. 61,372 (1997)("*FERC June 1997 Merger Order*").
Footnote No. 3
Exhibit 14, Chapter 3, at 11 ("Stewart Rebuttal").
Footnote No. 4
Stewart Rebuttal at 9-10.
Footnote No. 5
See Opinion of the Attorney General on Competitive Effects of Proposed Merger between Pacific Telesis Group and SBC Communications, Inc., 79 Cal.Ops.Atty.Gen. 301 (1996); Opinion of the Attorney General on Competitive Effects of Proposed Merger of American Telephone & Telegraph Company and McCaw Cellular Communications, Inc., 77 Cal.Ops.Atty.Gen. 50 (1994); Opinion of the Attorney General on Competitive Effects of Proposed Merger of GTE and Contel Corporations, Submitted Pursuant to PU Code Section 854(b)(2); Opinion of the Attorney General on the Proposed Acquisition of San Diego Gas and Electric Company by SCEcorp, the Parent of Southern California Edison Co., 73 Cal.Ops.Atty.Gen. 366 (1990).
Footnote No. 6
Section 854(b) provides in pertinent part:
Before authorizing the merger, acquisition or control of any electric, gas, or telephone utility organized and doing business in this state . . ., the commission shall find that the proposal does all of the following:
(1) Provide short-term and long-term benefits to ratepayers.
(2) Equitably allocates, where the commission has ratemaking authority, the total short-term and long-term forecasted economic benefits, as determined by the commission, of the proposed merger, acquisition, or control,

between shareholders and ratepayers. Ratepayers shall receive not less than 50 percent of those benefits.
(3) Not adversely affect competition. In making this finding, the commission shall request an advisory opinion from the Attorney General regarding whether competition will be adversely affected and what mitigation measures could be adopted to avoid this result.

Footnote No. 7

Applicants' Opening Brief, at 86. These QF facilities included 67 MW capacity wastewood, 30 MW capacity hydroelectric, and 37 MW capacity landfill projects. Application at 16 n.11.

Footnote No. 8

SDG&E wholesale sales are "economy energy sales and short-term sales of capacity." *FERC June 1997 Merger Order*, mimeo at 6.

Footnote No. 9

Exhibit 2 at 30 ("Hieronymous Direct").

Footnote No. 10

According to SCUPP, SDG&E "represents a total load of about 350 MMcfd." Exhibit 105 at 52 ("Yap Direct").

Footnote No. 11

Hieronymous Direct at 30. In fact, San Diego Gas & Electric purchases its gas supplies from out-of-state producers, and transports them to San Diego over interstate pipelines and the SoCalGas intrastate system. Exhibit 104 at 6 ("Taylor Direct").

Footnote No. 12

Application at 30.

Footnote No. 13

The applicants state that AIG is the nation's 15th largest gas marketer and the 19th largest electricity marketer. Exhibit 14, Chapter 1 at 44 ("Hieronymous Rebuttal"). Edison claims that AIG is the tenth largest gas marketer in the United States. Exhibit 209 at 17 ("Carpenter Rebuttal").

Footnote No. 14

Hieronymous Direct 6.

Footnote No. 15

Following "guidance" proceedings, FERC conditionally approved the ISO and PX on October 30, 1997. *Pacific Gas and Elec. Co., San Diego Gas & Elec. Co., and Southern Cal. Edison Co*. 81 FERC par. 61,122 (1997) ("*FERC October 1997 ISO/PX Order*"). *See Pacific Gas and Elec. Co., San Diego Gas & Elec. Co., and Southern Cal. Edison Co*., 77 FERC par. 61,204 (1996) ("*FERC November 1996 ISO/PX Order*"); *Pacific Gas and Elec. Co., San Diego Gas & Elec. Co., and Southern Cal. Edison Co*., 77 FERC par. 61,265 (1996) ("*FERC December 1996 ISO/PX Order*"), and *Pacific Gas and Elec. Co., San Diego Gas & Elec. Co., and Southern Cal. Edison Co*., 80 FERC par. 61,128 (1997) ("*FERC July 1997 ISO/PX Order*").

Footnote No. 16

Exhibit 2, Attachment A, Chapter III at III-9: Southern California Edison Company and San Diego Gas & Electric Company Report on Horizontal Market Power Issues ("Hieronymous MBR").

Footnote No. 17

Hieronymous Direct at 5. Firm purchases during 1996 were 1,434 MW. *Id*.

Footnote No. 18

Hieronymous Direct at 5 n. 7.

Footnote No. 19

"After the transition period, the Companies' participation in the PX will be voluntary." *FERC December 1996 ISO/PX Order*, mimeo at 2.

Footnote No. 20

End users who pay exit fees, however, can "directly access" suppliers in the wholesale market which are "interconnected to the ISO grid (directly or through wheeling arrangements)." Exhibit 2, Attachment A at I-5.

Footnote No. 21

After January 1, 1998, "utilities that join the ISO and PX will sell the output from their generating stations into the PX." Yap Direct at 75. "A uniform market-clearing price for PX buyers in a congestion management zone will be established based on the cost of the marginal generator in that zone for each hour." *FERC December 1996 ISO/PX Order*, mimeo at 3.

Footnote No. 22

The Commission ordered Edison and PG&E to sell at least 50 percent of their fossil-fuel-fired generation capacity. *FERC December 1996 ISO/PX Order*, *supra*, at 26. PG&E will divest nearly all of its gas-fired capacity. Exhibit 125, Chapter 2 at 77 ("Graves Direct"). Edison's Board of Directors has voted to divest all 9,600 MW of its gas generation. *Id*.

Footnote No. 23

Graves Direct at 84.

Footnote No. 24

The schedules devised by the PX, however, "are subject to adjustment by the ISO for reliability and congestion management purposes." *FERC November 1996 ISO/PX Order*, *supra*, at 61,804.

Footnote No. 25

"The price received for energy sold into the PX will be established through a 'second price auction.' . . . [Thus,] the highest cost unit that is needed in order to meet the hour's demand will establish the price for power in that hour." Yap Direct at 75.

Footnote No. 26

"Must-run" units, would be "certain generating units the Companies would designate to provide necessary support services to the transmission system at cost-based rates." *FERC December 1996 ISO/PX Order*, mimeo at 34-35 n. 48. Under "call contracts" proposed by the IOUs, these must-run units "would be paid a reservation fee or demand charge to be available. When that unit is required by the ISO to generate for reliability purposes, it would be paid its variable operating costs. When it is not required to generate, it would be treated like any other generator, *i.e.*, it would be dispatched based on its bid and paid the market price." *FERC December 1996 ISO/PX Order*, mimeo at 25-26.

Footnote No. 27

ISO Agreement B discussed below "provides an availability payment which covers the annual contribution to the initial capital investment, fixed fuel costs, fixed annual O&M costs, and annual auxiliary power costs; it also provides a payment for running costs when a unit is called to run." *FERC October 1997 ISO/PX Order*, *supra*, at 251.

Footnote No. 28

FERC October 1997 ISO/PX Order, *supra*, mimeo at 219-20. SDG&E expects to enter into "Agreement B," which "is intended for units that can participate in the market profitably in some periods but not in others."

Footnote No. 29

FERC December 1996 ISO/PX Order, mimeo at 34 n. 48. "In the restructured California energy market, at least during the initial years of operation, nuclear units, QF contracts and pre-existing wholesale purchase contracts will not be bid into the PX and market-based prices will not apply to their output. Instead, these will be regulatory must-take resources scheduled by the ISO." Exhibit 2, Attachment B at par. 30: Affidavit of Joe D. Pace ("Pace MBR").

Footnote No. 30

Pace MBR at par. 27.

Footnote No. 31

Hieronymous MBR at III-15.

Footnote No. 32

ISO Agreement A will actually govern SDG&E from January 1, 1998 to April 1, 1998, after which Agreement B will be effective. "[T]he ISO has committed to revise the Agreement [B] by October 31, 1998." *FERC October 1997 ISO/PX Order*, *supra*, mimeo at 225.

Footnote No. 33

FERC October 1997 ISO/PX Order, *supra*, mimeo at 251; Hieronymous Rebuttal at 5 n. 1.

Footnote No. 34

Proposed Decision of ALJ Minkin, A.96-08-001, slop op. at 50 (Oct. 20, 1997).

Footnote No. 35

FERC October 1997 ISO/PX Order, *supra*, mimeo at 233-235.

Footnote No. 36

An ISO "Oversight Board" will (1) establish nominating/qualification procedures and determine the composition of the board representation and select the ISO and PX Governing Board members and (2) serve as a permanent appeal board for reviewing ISO Governing Board decisions. *FERC November 1996 ISO/PX Order*, *supra*, at 61,817

Footnote No. 37

See Hieronymous Direct at 21.

Footnote No. 38

FERC November 1996 ISO/PX Order, *supra* at 61,799.

Footnote No. 39

See *FERC July 1997 ISO/PX Order*, *supra*, at 26-27; *FERC November 1996 ISO/PX Order*, *supra*, at 61,828-61,834 (discussing congestion pricing).

Footnote No. 40
Stewart Rebuttal at 4.
Footnote No. 41
Line 401 runs from the California-Oregon border at Malin to the Kern River Station. That line, which went into service on November 1, 1993, has an average annual firm capacity of 755 MMcf per day.
Footnote No. 42
Stewart Rebuttal at 4. Edison claims, though, that SoCalGas does not "list Hector as a delivery point." Carpenter Direct at 37-38.
Footnote No. 43
Stewart Rebuttal at 4. IID estimates that the system capacity is 3,700 MMcfd. Exhibit 104 at 23 ("Taylor Direct").
Footnote No. 44
Stewart Rebuttal at 9.
Footnote No. 45
Taylor Direct at 5; Stewart Rebuttal at 3. *See* Yap Direct at 69. The SoCalGas "noncore throughput *excluding* SDG&E's load exceeds 1 bcf/d." Stewart Rebuttal at 32.
Footnote No. 46
Exhibit 115 at 25 ("Roach Direct"); Taylor Direct at 6.
Footnote No. 47
Id.
Footnote No. 48
SCUPP alleges that the intrastate system is an "essential facility." Yap Direct at 65.
Footnote No. 49
Stewart Trans. at 2595.
Footnote No. 50
Stewart Trans. at 2556.
Footnote No. 51
SoCalGas estimates core demand from a statistical model and noncore demand from gas nomination information. Stewart Rebuttal at 5.
Footnote No. 52
"[O]ut-of-state sources supplied the vast majority -- approximately 84% -- of the total demand in southern California in 1996." Carpenter Direct at 21.
Footnote No. 53
Stewart Rebuttal at 5.
Footnote No. 54
See Stewart Trans. at 2560-2563. *See also* Stewart Trans. at 2407-2411, 2414 (discussing the consequences to SoCalGas under the Gas Cost Incentive Mechanism (GCIM) "of not meeting injection or withdrawal targets or storage levels").
Footnote No. 55
Stewart Rebuttal at 5. "SoCalGas owns all of the approximately 115 Bcf of gas storage in southern California. SoCalGas reserves 70 Bcf of this capacity for its core customers, reserves 5 Bcf for balancing, and markets the remaining 40 Bcf to noncore customers." Taylor Direct at 44.
Footnote No. 56
Carpenter Direct at 49.
Footnote No. 57
Stewart Trans. at 2401; Stewart Rebuttal at 7.
Footnote No. 58
A custody cut occurs when SoCalGas notifies an interstate pipeline that it cannot accept the full amount of gas nominated for delivery at a particular receipt point. Approximately 600 custody cuts occurred in 1995 and 1996. SoCalGas matches the window at that receipt point by pro-rating shippers' nominations. Carpenter Direct at 34.
Footnote No. 59
See Carpenter Direct at 31-37; Stewart Trans. at 2551-2557. SoCalGas imposes Rule 30 when its system is overnominated. Carpenter Direct at 35. SoCalGas has "called" Rule 30 events six times in 1997. Carpenter Direct at 36.
Footnote No. 60
Stewart Trans. at 2406-2409, 2547-2555; Stewart Rebuttal at 6-7.
Footnote No. 61

Re Gas Utility Procurement Practices and Refinement to the Regulatory Framework for Gas Utilities, D.91-11-025, mimeo at 20; 41 CPUC 2d 668 (1991)(CPUC 1990). *See* Exhibit 14, Chapter 2 at 9 n.24 ("Leitzinger Rebuttal").
Footnote No. 62
SoCalGas estimates that it posts transactions on GasSelect "within the hour." Stewart Trans. at 2578.
Footnote No. 63
Stewart Trans. at 2575-2576, 2583.
Footnote No. 64
Stewart Trans. at 2577.
Footnote No. 65
See Broadman and Kalt, *How Natural Is Monopoly? The Case of Bypass in Natural Gas Distribution Markets*, 6 Yale J. on Reg. 181 (1989); Kelly, *Intrastate Natural Gas Regulation: Finding Order in the Chaos*, 9 Yale J. on Reg. 365 (1992); Pierce, *Intrastate Natural Gas Regulation: An Alternative Perspective*, 9 Yale J. On Reg. 407 (1992). Because PG&E and SoCalGas have "exclusive service territories," PG&E cannot "offer any customer in SoCalGas' service area direct connection to Line 300-A or -B." Stewart Trans. at 2776-2777.
Footnote No. 66
Exhibit 114, Chapter 1, at 5-7 ("Larsen Direct"); Exhibit 114, Chapter 2 at 9 ("Wadlington Direct"); Stewart Rebuttal at 34-35 ("There appears to be no dispute that Kern River only acceded to provide SoCalGas the option to purchase its California facilities as a means to induce SoCalGas and the Commission to withdraw their opposition before the FERC"); Stewart Trans. at 2524-2525, 2783-2786; Roach Direct at 63; Yap Direct at 58-60.
Footnote No. 67
Roach Direct at 25.
Footnote No. 68
Hieronymous Direct at 28.
Footnote No. 69
See Taylor Direct at 12, 51 ("SoCalGas provides gas transportation to SDG&E at less than the regulated rate because SDG&E could bypass SoCalGas gas transportation"); Yap Direct at 52-53. *But see* Stewart Rebuttal at 38 (contending that SDG&E merely shifted risk by agreeing to pay a higher demand charge and lower volumetric rate).
Footnote No. 70
Larsen Direct at 9. *See* Stewart Trans. at 2744 ("we compete vigorously against bypass and against all kinds of bypass including by wire and everything else"), 2772-2775 (referring to "local gas production as a form of competition," and competition from "municipalization efforts similar to Vernon's"); Leitzinger Rebuttal at 30 ("new construction" has "been a source of competitive discipline in the pipeline business"); Roach Direct at 69 (estimating that Kern River customers pay approximately 18% less for their transportation services).
Footnote No. 71
Yap Direct at 50.
Footnote No. 72
Stewart Rebuttal at 31. *See* Leitzinger Rebuttal at 31.
Footnote No. 73
Stewart Rebuttal at 20.
Footnote No. 74
The CPUC established the ITCS in Decision No. 91-11-025, *Re Gas Utility Procurement Practices and Refinement to the Regulatory Framework for Gas Utilities*, 41 CPUC 2d 668 (1991). The ITCS for any shipment equals the difference between "the maximum rates charged by the interstate pipelines for firm capacity" ("as-billed rate") and the actual shipping rate. The PUC capped ITCS charges recoverable from core customers at 10 percent of the core's total capacity reservation costs. D.91-11-025, mimeo at 51. Noncore customers, including Edison, pay all additional ITCS costs. The PUC annual "BCAP" proceedings establish the size of these ITCS funds and transfer balances from year to year. The amount SoCalGas and other intrastate pipelines can recover from ITCS funds is also limited, in some cases, by settlements which have discounted the maximum rate which the end-user must pay. Since May 1, 1996, SoCalGas has also offered "released" capacity on interstate pipelines at rates "posted" on "electronic bulletin boards" for all requirements beyond those of its core customers. As SoCalGas releases capacity, resulting revenues reduce the ITCS surcharge amount.
Footnote No. 75
See Stewart Trans. at 2744.
Footnote No. 76
Leitzinger Rebuttal at 8.
Footnote No. 77

Doane and Spulber, *Open Access and Evolution of the U.S. Spot Market for Natural Gas, 37 J.L. & Econ. 477, 479 (1994)*; Black and Pierce, *The Choice between Markets and Central Planning in Regulating the U.S. Electricity Industry*, 93 Columbia L.Rev. 1339, 1343 (1993) (the electricity industry combines "*production* of wholesale electricity; *transmission* of bulk power over high-voltage lines from power plants to local geographic areas; and *distribution* of power to retail customers").

Footnote No. 78

DOE/EIA, *Natural Gas 1996, Issues and Trends*, at 40 (Washington, D.C. Dec. 1996). Thus, each "pipeline was a link in a supply chain from a field whose resources were dedicated by contract to that line to the distribution company which was obligated by contract to buy gas from the pipeline." De Vany and Walls, *The Emerging New Order in Natural Gas*, at 5 (Quorum Books 1995).

Footnote No. 79

Order No. 636, *Pipeline Service Obligations and Revisions to Regulations Governing Self-Implementing Transportation and Regulation of Natural Gas Pipelines After Partial Wellhead Decontrol under Part 284 of the Commission's Regulations*, F.E.R.C. Stats. & Regs. (CCH) par. 30,939, at 30,396 (1992). *See* Black and Pierce, *supra*, at 1351; Pierce, *Reconstituting the Natural Gas Industry from Wellhead to Burnertip*, 9 Energy L.J. 1 (1988).

Footnote No. 80

The 1978 Natural Gas Policy Act, together with FERC Order 436 and the 1989 Decontrol Act, removed all controls over the wellhead price of natural gas. *Order 636*, *supra*, at 30,397. "Take or pay" disputes subsequently arose, however, because price regulation was retained for "old," "high cost," and other subcategories. "By the end of 1986, $10 billion worth of contracts were involved in take-or-pay disputes." Doane & Spulber, *supra*, at 483.

"Take-or-pay liabilities arise from a typical provision in a contract between an LDC and a gas producer which obliges the LDC to take a minimum volume of gas from the producer or pay for it anyway." Kelly, *supra*, 9 Yale J. on Reg. at 361 n.16. Order 436 "gave pipelines facing mounting take-or-pay liability the right to convert their sales obligations under their wellhead contracts to transportation entitlments from other suppliers." Fagan, *From Regulation to Deregulation: The Diminishing Role of the Small Consumer within the Natural Gas Industry*, 29 Tulsa L.J. 707, 721 (1994). FERC Order 500 attempted to resolve further disputes by, among other things, allowing the establishment of a "gas inventory charge" (GIC). Lyon and Hackett, *Bottlenecks and Governance Structures: Open Access and Long-term Contracting in Natural Gas*, 9 J.Law. Econ. & Org. 380, 387 (1993). Order 500, however, "fared poorly on judicial review." *United Distribution Cos*. v. *F.E.R.C.*, 88 F.3d 1105, 1125-26 (D.C.Cir. 1996).

Footnote No. 81

DOE/EIA, *supra*, at 40.

Footnote No. 82

Leitzinger Rebuttal at 16.

Footnote No. 83

Leitzinger Rebuttal at 25.

Footnote No. 84

Regulation of Natural Gas Pipelines after Partial Wellhead Decontrol, F.E.R.C. Stats. and Regs. par. 30,665 (1985), *vacated and remanded*, *Associated Gas Distributors* v. *FERC*, 824 F.2d 981 (D.C.Cir. 1987).

Footnote No. 85

Doane & Spulber, *supra*, at 477; *Order 636*, *supra*, at 30,396.

Footnote No. 86

"Among the central goals of Order Nos. 436 and 636 has been the conversion of bundled sales arrangements into separate transportation and gas sales transactions. On the transportation side, the Commission recognized that while much of the nation's interstate pipeline capacity was reserved for firm transportation, those transportation rights ultimately were not being utilized. . . . FERC therefore sought to develop an active 'secondary transportation market,' with holders of unutilized firm capacity rights reselling them in competition with any capacity offered directly by the pipeline." *United Distribution Cos.* v. *F.E.R.C.*, 88 F.3d 1105, 1149 (D.C.Cir. 1996). *See also* Samuels, *The D.C. Circuit Review: September 1992-August 1993*, 62 Geo. Wash.L.Rev. 718, 740 (1994) ("Order 636 mandates pipelines to 'unbundle' their gas services" and "offer the same quality of service to all potential customers, irrespective of where the gas was purchased.").

Footnote No. 87

"Brokering arrangements allowed a holder of firm capacity rights (the "releasing shipper") to sell those rights to a 'replacement shipper.' The transaction took place directly between the two parties, and the replacement shipper essentially stepped into the shoes of the releasing shipper." *United Distribution Cos*., *supra*, 88 F.3d at 1149.

Footnote No. 88

Id.

Footnote No. 89
Edison alleges that, in developing that offer, SoCalGas can "take as tough a negotiating stance as it wants because there is no regulatory requirement for it to release any of the capacity it holds and the ITCS guarantees full recovery of all cost associated with the capacity." *Opening Brief of Southern California Edison*, at 40. Edison further alleges that "SoCalGas' minimum bid, minimum take, and other capacity release practices -- by withholding capacity from the market -- have the potential to raise the price of gas at the southern California border from what it otherwise would have been." Carpenter Direct at 53. As indicated below, however, this theory fails to account for the full extent of the competition that exists throughout the four basin interstate market. It also fails to explain how SoCalGas can limit supply in a market where unused capacity rights revert to the pipeline, which can then sell that capacity as interruptible transportation. Leitzinger Rebuttal at 20. Finally, Edison fails to reconcile its theory that SoCalGas has absolute discretion in establishing its opening bid with evidence that "over 70 percent of all SoCalGas capacity releases occur at prices *under* the initial opening offer." Stewart Rebuttal at 25; Leitzinger Rebuttal at 25.
Footnote No. 90
Leitzinger Rebuttal at 19. "[E]ach interstate pipeline is required to establish and administer an electronic bulletin board ('EBB') . . . The EBB caries information about available and consummated capacity release transactions. For example, holders of excess firm capacity rights may 'post' their available capacity on the EBB. . . . *Pipelines* are also required to post on the EBB any firm capacity that they have available for sale, where the capacity competes for buyers against capacity made available for resale by shippers." *United Distribution Cos*., *supra*, 88 F.3d at 1150.
Footnote No. 91
United Distribution Cos., *supra*, at 1150-1151. FERC requires that end users contract with gas producers during "bid week." Bid week "generally occurs about the last week of the previous month." Exhibit 353, Vol. I, at 56:2-4 ("Lorenz Depo.").
Footnote No. 92
Leitzinger Rebuttal at 21. *See* Yap Direct at 21.
Footnote No. 93
Stewart Rebuttal at 22. Transwestern and El Paso substantially increased the capacity of those pipelines in 1991, and again in 1996. Leitzinger Rebuttal at 24. *See* Stewart Rebuttal at 23.
Footnote No. 94
PG&E "transports this gas across northern California to an interconnection with the SoCalGas system in Kern County, providing access to Canadian gas supplies for customers in southern California." Taylor Direct at 33.
Footnote No. 95
Leitzinger Rebuttal at 16; Leitzinger Trans. at 3148, 3155.
Footnote No. 96
Following its line 401 expansion, PG&E likewise increased its transportation of Canadian gas into California, while announcing plans to terminate its 1.14 Bcf/d capacity contract with El Paso. Leitzinger at 21.
Footnote No. 97
Leitzinger Trans. at 3164. Edison notes that El Paso and Transwestern carry gas to California "from Canada via Northwest pipelines." Carpenter Direct at 21.
Footnote No. 98
Leitzinger Trans. at 3167. *See* Samuels, *supra*, 62 Geo.Wash.L.Rev. at 722 (Gas service is either provided on a firm or interruptible basis.)
Footnote No. 99
Leitzinger Rebuttal at 16.
Footnote No. 100
Leitzinger Rebuttal at Exhibit JJL-6, 24 (discussing "netback pricing"); Leitzinger Trans. at 3149-50. *See also* Leitzinger Rebuttal at 16 ("[T]o compete for southern California customers Canadian producers on some occasions agreed to contract pricing involving a netback price starting with the price of southwest gas delivered to southern California"); Leitzinger Trans. at 3145 ("if the price of transportation capacity goes up, it has the effect of lowering the basin price").
Footnote No. 101
Black and Pierce, *supra*, at 1348.
Footnote No. 102
Order No. 888, *Promoting Wholesale Competition through Open Access Non-Discriminatory Transmission Services by Public Utilities; Recovery of Stranded Costs by Public Utilities and Transmitting Utilities*, F.E.R.C. Stats. & Regs. (CCH) par. 31,036 (1996). FERC also effectively deregulated non-firm transmission services. *Id*. at 31,743.
Footnote No. 103

Black and Pierce, *supra*, at 1349.

Footnote No. 104

Black and Pierce, *supra*, at 1350.

Footnote No. 105

Cities of Anaheim, Cal., et al. v. *Southern Cal. Edison Co*., 1990-2 Trade Cases par. 69,246 at 64,899-64,900 (C.D.Ca. 1990), *affd*. 955 F.2d 1363 ("*Anaheim* v. *Edison*").

Footnote No. 106

Exhibit 379 at 4: DeVany and Walls, *Open Transmission and Spot Markets for Power* (July 1997)("De Vany and Walls"). *See* Hieronymous Direct at 16-17 ("the WSCC transmission grid . . . is characterized by a great number of interconnections and includes companies with transmission ownership and rights covering wide geographic areas.") The WSCC includes two regional transmission groups, the Western Regional Transmission Association and the Northwestern Regional Transmission Association, both of which require members to provide open access, comparable service tariffed transmission services. *WRTA*, 71 FERC par. 61,158 (1995); *NWRTA*, 71 FERC par. 61,397 (1995).

Footnote No. 107

The WSPP, a power pool consisting of approximately 70 WSCC members, allows participating electric utilities to sell economy energy, capacity service and transmission service at "rates determined between predetermined price floors and ceilings." *WSPP*, 55 FERC par. 61,099 at 61,300. In approving the WSPP, FERC set the ceiling rate for power sales at "sellers' forecasted incremental cost plus up to . . . 18.3 mills/kWh." *Id*. at 61,321. Because WSPP and other applicable price ceilings are rarely binding, however, the vast majority of WSCC sales are effectively unregulated. Hieronymous Trans. at 2971. *See* Graves Direct at 96 (referring to "(largely) unregulated generation").

Footnote No. 108

Graves Direct at 84. The annual average WSCC load is 82,000 MW. Graves Direct at 79.

Footnote No. 109

"The network provides multiple, alternative connections between generating plants, substations, and load centers, as well as multiple interconnections with other control areas, utilities and regions." De Vany and Walls, *supra*, at 6.

Footnote No. 110

LADWP, for example, obtains power from generation units located in the eastern half of Montana. Hieronymous Direct at 17. Likewise, after January 1, 1998, TRW will obtain power for its 44 California facilities from Montana Power Group. *See TRW to Switch to Montana Energy Firm*, Los Angeles Times (Orange Cty.), Nov. 6, 1997, at D1.

Footnote No. 111

See Hieronymous Trans. at 2973-2974 ("[A] loop flow . . . refers to the fact that electrons flow in the path of least resistance according to Kirchoff's laws. And so despite that you have a contract path from A to B, the electrons may actually go from A to C to B, or may even never get to B as electrons at all, and that's a loop flow. It loops around the area covered by the contract path."). Thus, loop flows can be broadly defined to include all flows "parallel" to the "direct" path between two points. <u>See</u> Watkiss and Smith, *The Energy Policy Act of 1992 -- A Watershed for Competition in the Wholesale Power Market*, 10 Yale J. on Reg. 447, 479 (1993) ("The difference between hypothetical flows on the contract path (point A directly to point B) and the actual electrical flows according to physical laws is referred to as 'loop flow' or parallel path, which is generally defined 'as the difference between scheduled and actual flow of electricity over a given established transfer path'"). We recognize, however, that loop flows can impose uncompensated costs ("externalities") on owners of parallel transmission systems and that some observers reserve the term for flows which are outside the transmission control area serving the parties to a particular transaction. *See* Fox-Penner, *Electric Power Transmission and Wheeling*, at 56 (Edison Electric Institute, 1990).

Footnote No. 112

Hogan, *Contract Networks for Electric Power Transmission*, 14 J.Reg.Econ. 211, 215 (1992)(also noting that "[o]ne of the most important economic implications of this prevalence of loop flow is that the power transmission highway is very unlike other highways, and analogies comparing other highways, railroads, or pipelines can be quite misleading").

Footnote No. 113

Hieronymous Trans. at 2976. Although they are now rare, displacement contracts provide a mechanism that is available to arbitrage price differentials resulting from "pancaking" and similar effects that might otherwise render transmission costs prohibitive.

Footnote No. 114

DeVany and Walls, *supra*, at 3 n.2.

Footnote No. 115

De Vany and Walls, *supra*, at 2, 15.

Footnote No. 116

Cointegration is a statistical relationship which "occurs when variability over time in two respective data series which cannot be associated with a trend in either series individually is closely related as between those data series." Leitzinger Rebuttal at 12. *See* Michaels and De Vany, *Market-Based Rates for Interstate Gas Pipelines: The Relevant Market and the Real Market*, 16 Energy L.J. 299, 327 (1995) ("If two areas are in the same competitive market, their prices will inhabit a band whose width reflects the cost of arbitrage. Those costs include transportation, risk exposure, and information about profitable opportunities. If competition exists, it will quickly bring disparate prices back within their arbitrage limits. . . . If the cost of arbitrage varies little over time, two areas are in the same market if the difference between their prices is relatively constant. The statistical technique known as cointegration provides a criterion under which to determine the relative constancy of such a difference.").

Footnote No. 117

Hieronymous Trans. at 2978.

Footnote No. 118

"Any interfacing utility (or generators/sellers with access to an interface) can sell into the PX and will be treated comparably to other market participants operating in the PX area." *FERC December 1996 ISO/PX Order*, mimeo at 4; *FERC July 1997 ISO/PX Order*, mimeo at 18 (rejecting a "special settlement rule" and related "reciprocal transmission service" requirements). In our *Reply Comments of Attorney General of California on Electric Industry Restructuring Proposals*, R.94-04-031 (Aug. 24, 1995), this office noted that an earlier version of the PX, which prohibited "Direct Access" transactions and which did not clearly permit sales into the PX by out-of-state suppliers, was vulnerable to coordinated bidding. We do not believe the formulation of the PX approved by FERC contains that defect.

Footnote No. 119

Joskow MBR at II-57 ("Other capacity, including that owned by entities other than the IOUs, and all of the IOUs' generating capacity that is divested or otherwise brought to market, is free to enter into physical bilateral contracts as an alternative to bidding into the PX. These contracts will be confidential and presumably could facilitate secret price cuts and output expansion that would further undermine the potential for coordinated pricing behavior by sellers in the PX.").

Footnote No. 120

Hogan, *Contract Networks for Electric Power Transmission*, 14 J.Reg.Econ. 211, 216 (1992).

Footnote No. 121

Nevertheless, FERC conducted such an analysis in one of its reviews of the PX and ISO. *See FERC December 1996 ISO/PX Order*, mimeo at 22.

Footnote No. 122

In the WEPEX proceedings before FERC, Edison contended that "there will in fact be large quantities of resources chasing a relatively small residual demand curve." Joskow MBR at II-51. In Table 14 of its submission, Edison noted that its "must-take" resources "include [its] nuclear units (2,222 megawatts), its QF purchases (3,688 megawatts), and its purchases from other utilities (2,002 megawatts)." Joskow MBR at II-45. Demand in "SCE's control area" ranges between a low of around 5,670 megawatts and a peak of around 13,500 megawatts. Accordingly, Edison roughly estimated that residual demand in its control area will vary between 837 and 5499 megawatts. PG&E faces similar supply and demand schedules. These amounts are a small percentage of supplies available from California and out-of-state suppliers in the wholesale market.

In fact, Edison argued that the capacity of the transmission system connecting California to out-of-state suppliers easily satisfies demand. Thus, for Edison, the lines from the desert Southwest "were never constrained and [have been] never even particularly close to being constrained" (Joskow MBR, at II-20) and the capacity of North to South lines have never been fully loaded. Joskow MBR, at II-20. Similarly, "there has been an abundance of unused transmission capability into SCE's control area at . . . high demand times--5,303 megawatts on average during summer peak hours, 6,056 megawatts on average during summer mid-peak hours, and 6,165 megawatts on average during winter mid-peak hours." Joskow MBR, at II-48.

The capacity of transmission lines from the Pacific Northwest includes 3200 megawatts over the Pacific Intertie (PACI), 1600 megawatts over the California Oregon Transmission Project (COTP), and 3500-3800 megawatts over Path 15. Pace MBR, at 24, 26. Power over these lines flows to southern California over the Midway to Vincent path. Joskow MBR, at II-21. Another path, the PDCI, "goes around PG&E's area and directly interconnects the Pacific Northwest with southern California." Pace MBR, at 24, 28. Although Path 15 can be individually constrained, these lines have so much excess capacity in the aggregate that 95 percent of the time, over 2,374 megawatts of their capacity was unused in 1995. Joskow MBR, at II-20. *See also* Pace MBR, at 25.

Footnote No. 123
Hogan defines the "efficient" short-run price of transmission as the difference between prices at delivery points. *See* Hogan, *supra*, at 214, 233.
Footnote No. 124
De Vany and Walls at 12-13, Table 2.
Footnote No. 125
Landes and Posner, *Market Power in Antitrust Cases*, 94 Harv. L.Rev. 937, 978 (1981).
Footnote No. 126
Id.
Footnote No. 127
Schmalensee, *On the Use of Economic Models in Antitrust: The ReaLemon Case*, 127 U.Pa.L.Rev. 994, 1010 (1979).
Footnote No. 128
Fisher, *Diagnosing Monopoly*, 19 Q.Rev.Econ. & Bus. 7, 15 (Summer 1979).
Footnote No. 129
U.S. v. *Connecticut National Bank*, 418 U.S. 656, 668 (1974). *See also* Stigler and Sherwin, *The Extent of the Market*, 28 J.L.Econ. 555, 556 (1985) ("[T]he market area embraces the buyers who are willing to deal with any seller, or the sellers who are willing to deal with any buyer, or both.").
Footnote No. 130
Spiller and Huang, *On the Extent of the Market: Wholesale Gasoline in the Northeastern United States*, 35 J.Ind.Econ. 131, 133 (1985). Spiller and Huang note: "Arbitrage costs, however, do not necessarily separate producers in different markets. Consider the case of two different geographic regions with one continuously exporting to the other. Prices will differ *exactly* by the arbitrage costs, and the two regions will be in the same economic market." *Id*. at 133 n.7.
Footnote No. 131
Areeda & Turner, 2 Antitrust Law par. 522a.
Footnote No. 132
See Leitzinger Rebuttal at 3, 10 (including within the relevant market "those locations where gas is bought and sold along the interstate gas supply network extending from [basins in the western United States] to points of interconnection with local California gas distribution systems"). *See also* Yap Direct at 29 (essentially alleging effects in the interstate market [*see* Leitzinger Rebuttal at 3] and referring to supplies from the "southwestern U.S., Rocky Mountain, and Canadian regions," but limiting the buyers within her proposed market to southern California customers). FERC uses "delivered gas" as the relevant product in its analysis and IID contends that the relevant product is "natural gas delivered to the burner tip." Taylor Direct at 32, 33. The relevant market employed by the applicants is generally equivalent to the combined interstate gas and intrastate gas transportation markets employed here.
Footnote No. 133
Stewart Rebuttal at 21.
Footnote No. 134
"The ability of customers to contract independently for pieces of the network acts both to discipline price differences along the network and bring locations across the network into competitive association with one another. Not only does the network mean that producers in the various basins compete and that pipelines serving the different basins compete, it also means that producers in one basin discipline pipeline charges in other basins and vice versa." Leitzinger Rebuttal at 16.
Footnote No. 135
Various intervenors allege a delivered gas product market, but they apparently exclude from the geographic market delivered gas supplies which can be economically transported to California. *See* FERC at 20.

Footnote No. 136
Leitzinger Rebuttal at Exhibit JJL-2.
Footnote No. 137
Leitzinger Rebuttal at 21.
Footnote No. 138
See Yap Direct at 29 (alleging a southern California gas procurement market).
Footnote No. 139
Interruptible and short term firm transmission are strong substitutes for capacity rights held by SoCalGas on the El

Paso and Transwestern pipelines. Leitzinger Rebuttal at 19. Because these rates interact so strongly with commodity prices, interstate gas transportation is not a separate product market. Leitzinger Rebuttal at 23 (discussing "derived demand"). Similarly, "inframarginal" southwest supplies, which have no price advantage at the California border, are included within the broader relevant market. Leitzinger Rebuttal at 14.

Edison alleges that the price of gas at the southwest border determines the price of gas coming from Canada and Rocky Mountain basins because the southwest is the "marginal supply region for California." Carpenter Direct at 24-25. It is true that prices at those basins are very strongly related. Leitzinger Rebuttal at 13, 26. We conclude in the absence of evidence of collusion, however, that those highly volatile prices are competitively determined. *See* Carpenter Direct at 27 ("gas prices vary significantly on a daily basis").

Footnote No. 140

Market share statistics are often misleading, however, and their value is particularly dubious when a proposed market is part of an integrated network. This is because any grouping composed of only a part of the network (such as the proposed capacity release and southern California gas procurement markets) will lack the required "gap in the chain of substitutes."

Footnote No. 141

Rebel Oil Co., Inc. v. *Atlantic Richfield*, 51 F.3d 1421, 1434 (9th Cir. 1995); *Ryko Mfg*. Co. v. *Eden Serv*., 828 F.2d 1215, 1232 (8th Cir. 1987). Thus, isolated concentration figures are inherently meaningless. *See* Landes and Posner, *supra*; Pace MBR at par. 23 (referring to "concentration statistics . . . calculated slavishly or interpreted mechanistically").

Footnote No. 142

FTC v. *Indiana Fed'n of Dentists*, 476 U.S. 447, 460-61 (1986); *Rebel Oil*, *supra*, at 1434.

Footnote No. 143

Hieronymous Trans. at 2979 Prior to open access, transmission services constituted separate product markets. *See Town of Concord*, *supra*, at 29; *Anaheim* v. *Edison*, *supra*, at 64,899-64,900.

Footnote No. 144

Hieronymous Rebuttal at 11. Thus, spot prices at Palo Verde and California "should be identical on a netback basis. That is, the Palo Verde price should equal the California electricity price, less the cost of interruptible transmission. The reason, simply, is that if electricity is available from Palo Verde at a lower price than the incremental price of producing it in California, utilities will purchase rather than generate." *Id*.

Footnote No. 145

Graves Direct at 78. In 1990, a federal district court rejected the WSCC as a relevant geographic market because plaintiff wholesale purchasers "were not completely free to purchase bulk power from . . . other suppliers in the western United States." *Anaheim* v. *Edison*, *supra*, at 64,899. FERC Order 888, however, subsequently provided wholesale purchasers with that freedom. *See also Town of Concord, Mass*. v. *Boston Edison Co*., 915 F.2d 17, 30 (1st Cir. 1990); Lopatka, *The Electric Utility Price Squeeze as an Antitrust Cause of Action*, 31 UCLA L.Rev. 563, 611 (1984).

Footnote No. 146

Similarly, FERC found that the relevant product was: "all capacity whose variable costs are no more than 5% above the market price," which FERC equated with the "cost of gas-fired steam generation." *FERC June 1997 Merger Order*, mimeo at 22. FERC, however, excluded out-of-state supplies from its analysis because the "Applicants did not prepare a delivered price analysis." *Id*.

Footnote No. 147

Joskow MBR at II-42.

Footnote No. 148

See Graves Direct at 79 (referring to all generation within one standard deviation of the 82,000 MW average WSCC load).

Footnote No. 149

Of the total WSCC capacity, coal plants account for 26 percent, gas/oil for 21 percent, hydro for 33 percent, nuclear for 6 percent, geothermal for 1 percent, and remaining plants for 13 percent. Yap Direct at 78.

Footnote No. 150

See, *e.g*., Roach Direct at 32, who "stacked" power plants within the WSCC from lowest to highest cost, and excluded "plants owned by competitive power suppliers" by "view[ing]" them as "must run." These plants, in fact, are not must run and their incentive will be to bid their full marginal costs, including their opportunity costs, into the PX.

Footnote No. 151

Thus, Edison claims that, "The reason that competition from generators outside California to import power [*sic*] does not counteract the effect of higher gas prices is that the margin of the WSCC supply curve is dominated by California gas capacity. The inexpensive hydro, coal and nuclear capacity that is available from out-of-state (as well as in-state) generating stations is being utilized most of the time in any case, so it is inframarginal and does not directly affect the electricity price." Carpenter Direct at 85-86. It is true that some plant owners must consider the costs they incur throughout the day as those of a joint product, requiring them to calculate all bids simultaneously. Hieronymous Trans. at 2983-2984. *See* Hirshleifer, *Peak Loads and Efficient Pricing*, 72 Q.J. Econ. 451 (1958). In general, however, out-of-state suppliers have sales alternatives throughout the WSCC and they "are going to bid where the prices are the highest, that's their incentive." Hieronymous Trans. at 2989.

Footnote No. 152

Edison contends that in "off-peak periods, bids are likely to be fairly close to short run variable cost (mostly fuel cost)." Graves Direct at 96.

Footnote No. 153

California utilities, on the other hand, will not recognize such costs because they will be required to sell their entire output to the Power Exchange.

Footnote No. 154

See Pace MBR at 40-41, 48, 57 (noting that swing analysis "fails to capture one extremely important source of potential supply responsiveness -- that is, the ability of owners with hydroelectric resources . . . to shape the output of those resources in an effort to maximize their value"). *See also* Graves Direct at 86 (explicitly recognizing the concept of opportunity costs and its applicability to the analysis of competition within the WSCC).

Footnote No. 155

Contrary to the positions taken by the applicants and other parties in this proceeding, when several types of generation sell electricity in California, gas will not be *the* marginal fuel, even if it (along with coal or hydro or other types of fuel) is *on* the margin, and even if gas-fired generation has the *highest* variable costs. *See* Taylor Direct at 13, 52 (gas fired generation is "expected to be the marginal generation"); Hieronymous Trans. at 2866; Hieronymous Rebuttal at 10 (referring to the "proportion of hours that gas delivered to southern California generators is the marginal fuel).

Footnote No. 156

Hieronymous Trans. at 2980.

Footnote No. 157

While the correlation between gas and electric prices is only .22 (Hieronymous Rebuttal at 11; Surrebuttal at 9), wholesale rates throughout the WSCC are strongly cointegrated. *See* De Vany and Walls, *supra*.

Footnote No. 158

Moreover, as then Judge Breyer recognized in assessing the market power of a low cost generation supplier, the "'extra profit' resulting from lower costs is not a monopoly profit," and the existence of these "economic rents" is "consistent with a perfectly competitive marketplace." *Town of Concord*, *supra* at 30. In a *competitive* market like the WSCC, the "opportunity costs" to a low cost firm foregoing alternative sales will equal its scarcity rents, which are the difference between the market price and its production costs.

Footnote No. 159

Merger Guidelines §1.01; *State of N.Y.* v. *Kraft General Foods, Inc*., 926 F.Supp. 321, 359 (S.D.N.Y. 1995).

Footnote No. 160

Hieronymous Trans. at 2976.

Footnote No. 161

Edison contends that "for the few percent of hours near peak demand (perhaps a few hundred out of 8760 hours per year), it is very likely that the marginal bid will *substantially* exceed short run costs of the marginal unit, particularly once the supply of peaking generation in the region tightens up." Graves Direct at 97. In fact, the optimal bid in a competitive auction will include variable and opportunity costs during both peak and off-peak periods.

Footnote No. 162

Yap Direct at 49.

Footnote No. 163

See U.S. v. *Syufy Enterprises*, 903 F.2d 659, 672 n.21 (9th Cir. 1990).

Footnote No. 164

Hieronymous Direct at 28.

Footnote No. 165

Posner, *Antitrust Law: An Economic Perspective*, at 63 (1976). It is not clear, however, whether SoCalGas has market power over those customers whose transmission rates are at the tariff level. *See State of Ill. ex Rel. Hartigan* v. *Panhandle Eastern*, 730 F.supp. 826, 905 (C.D.Ill. 1990).

Footnote No. 166
See U.S. v. *Connecticut Nat'l Bank*, 418 U.S. 656, 669 (1974).
Footnote No. 167
Areeda and Hovenkamp, *Antitrust Law*, § 1015.1 (1997 Supp.).
Footnote No. 168
U.S. v. *Mercy Health Services*, 1995-2 Trade Cases par. 71,162.
Footnote No. 169
Section 7 "deals in 'probability,' not 'ephemeral possibilities.'" *U.S.* v. *Marine Bancorporation, Inc*., 418 U.S. 602, 622-623 (1974). "There must be 'the reasonable probability' of a substantial impairment of competition to render a merger illegal under § 7. A 'mere possibility' will not suffice." *Fruehauf Corp*. v. *F.T.C*., 603 F.2d. 345, 351 (2nd Cir. 1979).
Footnote No. 170
Fruehauf Corp. v. *F.T.C*., 603 F.2d 345, 351 (2d Cir. 1979), *citing* R. Posner, *Antitrust Law, An Economic Perspective* 200 (1976). In fact, the FTC and the DOJ "appear not to have challenged a purely vertical transaction during the period from 1981-1993." Roscoe B. Starek, III, *Reinventing Antitrust Enforcement? Antitrust Enforcement at the FTC in 1995 and Beyond*, Remarks at "A New Age of Antitrust Enforcement: Antitrust in 1995" (Marina Del Rey, CA Feb. 24, 1995).

In general, "there is but one maximum monopoly profit to be gained from the sale of an endproduct." *See Town of Concord*, 915 F.2d 17, 23 (1st Cir. 1990) (noting that "several members of the Supreme Court have pointed out [this] 'widely accepted' (albeit 'counterintuitive') economic argument"). It is for this reason that the "government's 1984 vertical merger guidelines are not concerned . . . with the possible use of vertical integration to 'leverage' monopoly from one market into another." Areeda & Hovenkamp, *supra*, par. 1015.1. *See also* 3A Areeda & Hovenkamp, *Antitrust Law*, par. 756b at 12; *Western Resources, Inc*. v. *Surface Transp. Bd.*, 109 F.3d 782 (D.C.Cir. 1997); *Alaska Airlines, Inc*. v. *United Airlines, Inc*., 948 F.2d 536 (1991), *cert. denied*, 112 S.Ct. 1603 (1992).

Relying in part upon the single monopoly rent theory, Judge (now Supreme Court Justice) Breyer rejected a claim in *Town of Concord* that the defendant utility manipulated the price of input generation and transmission services to "squeeze" the plaintiff in the endproduct delivered wholesale electricity market. Here, the endproduct is also delivered wholesale electricity, but the inputs are interstate gas, intrastate gas transmission, and electricity transmission. "[A] price squeeze occurs when the integrated firm's price at the first level is too high, or its price is too low, for the independent to cover its costs and stay in business." *Town of Concord*, *supra*, 915 F.2d at 18. The swing capacity theory advanced by the intervenors essentially alleges that the merged entity will "squeeze" the gas-fired plants served by SoCalGas. *See* Yap Direct at 67. Because SoCalGas tariff rates are not binding for all noncore customers, this merger presents a mixture of the regulated and unregulated cases analyzed in the *Town of Concord* decision.
Footnote No. 171
Areeda & Turner, 2 *Antitrust Law* par. 527a at 376 (1978).
Footnote No. 171.1
See Stewart Rebuttal at 27. The Commission has authorized discounts below existing tariff levels only for the Mandalay station, in D.95-02-043, and for cogeneration plants with total capacity of 364 MW (whose capacity appears in QF contracts with purchasing utilities approved by the Commission), in D.93-06-096, D.93-11-021, D.95-01-040, D.95-11-048, D.96-09-096, D.97-04-071, D.97-03-005. We understand that no other cogeneration discounts have been filed with the Commission. *See also* Applicants' Opening Brief at 99-107.
Footnote No. 172
Apart from the issue of whether out-of-state competition constrains SoCalGas transportation rates, it is also highly questionable whether the merged entity would benefit from higher rates. As the applicants note, "SDG&E's share of revenues from SONGS is subject to the incentive-based ratemaking mechanism approved by the Commission in D.96-01-011 and D.96-04-059. Under this mechanism, the market price of electricity will have no impact on SDG&E's earning from SONGS through 2003." Surrebuttal at 18. For other plants, higher transportation costs will reduce the stranded costs recoverable by the merged entity during the four year transition period, during which time AB 1890 has "frozen" retail electricity rates. The merged entity must recover all of these stranded costs through a Competitive Transition Charge ("CTC") which expires in 2002.
Footnote No. 173
See WSCC, *Summary of Estimated Loads and Resources* (April 1997).
Footnote No. 174
Edison acknowledges the applicability of the opportunity cost concept to the analysis of competition within the

WSCC and, similarly, that suppliers will bid into the PX what "they believe the market will bear." Graves Direct at 86, 96.

Footnote No. 174.1

As the Ninth Circuit has recognized, a firm cannot control prices without "significant" entry barriers -- "they must be capable of constraining the normal operation of the firm to the extent that the problem is unlikely to be self-correcting." *Rebel Oil Co., Inc.* v. *Atlantic Richfield Co*., 51 F.3d 1421, 1439 (9th Cir. 1995). *See also Ryko Mfg. Co*. v. *Eden Services*, 823 F.2d 1215 (8th Cir. 1987)("direct evidence of competitive pressure -- demonstrated by a significant number of viable competitors in the market [citations omitted] or even by the product's price sensitivity -- indicates a lack of market power"). In any event, it is questionable whether the intermittent price increases hypothesized by Edison would constitute an unlawful exercise of market power. *Colorado Interstate Gas* v. *Natural Gas Pipeline*, 885 F.l2d 683, 695 (10th Cir. 1989)(refusing to find violation of Sherman Act "where the evidence indicates that a firm's ability to charge monopoly prices will necessarily be temporary"); *Metro Mobil CTS, Inc*. v. *Newvector Communications, Inc*., 661 F.Supp. 1504, 1523-24 (1987).

Footnote No. 174.2

De Vany and Walls, *supra*. *See also* Lehr & Van Vactor, *Evolution of Wholesale Power Price Structures in the Western Power Market: Implications for US Power Markets*, The US Power Market/Risk Publications (July 1997) at 233 ("The synchronous movement of prices within [the western United States], combined with a fragmented and diverse group of suppliers, indicate there is substantial competition in the market.").

Footnote No. 175

It is widely understood that "[a]lternative simulation models can give substantially different results." Lande & Langenfeld, *The Evolution of Federal Merger Policy*, 11 Antitrust at 9 n.22 (Spring 1997). Thus, "the answers may come flowing out of the machine highly dependent upon the approach, depending upon how the data are handled, depending upon the framework, the functional form, and the method of estimation. . . . [I]n an adversarial setting with different data sets, lack of cooperation, and a very narrow group of players, only a few of whom understand the technical issues, the outcome can be really skewed." *Interview with Economist Robert D. Willig*, 11 Antitrust 11, at 13 (Spring 1997).

In this case, Edison and the applicants rely upon swing capacity models to support their positions on the questions of whether the merged entity would have the ability and incentive to manipulate California electricity prices. The applicants' PROSYM/MULTISYM model, based upon assumptions listed on "four inches of printout material," uses a "cost minimization approach . . . to identify the lowest cost mix of generators available to serve the electric load." Hartman Trans. at 2434; Surrebuttal at 5. Inputs to the model include "fuel prices, transmission line, and pathways, and the ratings on those pathways." Hartman Trans. at 2434. From the resulting least-cost mix, the hourly marginal clearing price is "calculated based on the marginal generator's marginal cost *and* allocation of that particular generator's commitment costs during the peak period load period." Surrebuttal at 6. This model predicts that increased gas prices (Hartman Trans. at 2459-2461) would reduce electricity sales by SDG&E and other southern California gas-fired plants (Hartman Trans. at 2449, 2452), increase sales for plants located in other parts of the WSCC (Hartman Trans. at 2449, 2452-55), and reduce revenues for the merged entity (Surrebuttal at 18).

Edison employed the Inter-Regional Electric Market Model (IREMM) of the WSCC to predict the effect on California electricity prices of "changes in the price of gas delivered to the California border." Graves Direct at 84. This model "segments" the market into California and the remainder of the WSCC and "forecast[s] the market price of electricity by simulating power trades between electric utilities or market areas based on opportunities to buy and/or sell electricity." Graves Direct at Attachment H. The IREMM model predicts that "a 5% gas price increase translates to a 3.8% electricity price increase." Graves Direct at 85.

For reasons discussed above, we conclude that both of those models are highly misleading because of their failures to account for competition from low cost, out-of-state supplies. Both models also overstate electricity revenues resulting from gas price increases because they assume the merged entity will receive the PX price, instead of the levels set forth in Agreement B. We do note, however, that PROSYM/MULTISYM, unlike IREMM, can simulate the effects of cost increases to gas-fired plants located in southern California. Graves Trans. at 3408. We also note Edison's admission that a hypothesized increase in electricity revenues resulting from higher gas prices would be more than offset by reduced transportation revenues. Graves Trans. at 3407.

Footnote No. 176

Riordan and Salop, *Evaluating Vertical Mergers: A Post-Chicago Approach*, 63 Antitrust L.J. 513 (1995). In any event, Riordan and Salop overstate the circumstances under which variable proportion models predict adverse competitive effects from vertical integration. *See* Reiffen and Vita, *Comment: Is There new Thinking on Vertical Mergers?*, 63 Antitrust L.J. 917 (1995). Moreover, the economic model upon which Riordan and Salop apparently rely contains extremely limiting game theory assumptions which necessarily restrict its applicability. *Id*. at 924-33 (noting that model uses a "static . . . game to analyze premerger equilibrium, [which] shift[s] implicitly to a multi-stage, dynamic game to analyze post-merger conduct"); Remarks of Roscoe B. Starek, III, *supra*, at 8 (noting that vertical integration models "are notorious for their lack of generality -- their inability to predict likely, as distinguished from possible, effect even under the most strictly devised theoretical conditions -- and for ignoring procompetitive rationales for vertical mergers that have greater empirical support"). Thus, Reiffen and Vita warn, "[e]nforcers must have some reason to believe that a particular model -- and a particular (anticompetitive) equilibrium of that model -- better describes behavior than some alternative model." *Id*. at 928.

Footnote No. 177

See Areeda & Hovenkamp, supra, at par. 759c at 38 ("When [a] primary market monopolist integrates into a competitive secondary market, no injury to competition is ordinarily apparent. . . . [This form of integration] -- vertical integration into a competitive market -- is a clear candidate for a rule of absolute legality.").

Footnote No. 178

See Yap Direct at 102-120;

Footnote No. 179

Yap Direct at 108.

Footnote No. 180

"Ensource or some other affiliate of SoCalGas could theoretically benefit from precisely the same of machinations today." *Applicants' Opening Brief*, at 112.

Footnote No. 181

A seller wishing to corner a market must be able to limit supply. The supply of futures contacts is not "fixed," however, because the total volume of contracts promising future delivery expands with each new contract that is written. *See* Hieronymous Trans. at 2982 ("People can just come piling into the market."). *See also* Easterbrook, *Monopoly, Manipulation, and the Regulation of Futures Markets*, 59 J. of Business S103, S109 (1986) ("Entry and exit [into futures markets] are so easy that monopoly cannot thrive."). Moreover, sellers wishing to corner a futures market must also control the underlying commodity market. *See Sanner* v. *Board of Trade of City of Chicago*, 62 F.3d 918, 927 (7th Cir. 1995)(recognizing that cash and futures markets move together).

Footnote No. 182

Few, if any, futures markets have been successfully cornered within the past 20 years. Hieronymous Trans. at 2981. *See* Easterbrook, *supra*, 59 J. of Business at S111 n.7 ("no one has ever seriously alleged, let alone documented, a manipulation of a financial futures contract"). The Hunt Brothers did attempt to monopolize silver futures, but their unsuccessful efforts cost them several billion dollars. Hieronymous Trans. at 2981; Easterbrook, *supra*, 59 J. of Business at S110 n.5.

Footnote No. 183

See Roach Direct at 73, Yap Direct at 58-60, Beach Direct at 31.

Footnote No. 184

We agree that the merged entity may be able to enhance its market power over intrastate gas transportation services by exercising those options, but there is no evidence that the gas-fired generation served by SoCalGas and these other two pipelines actually have market power in the broad wholesale electricity market.

Footnote No. 185

See Easterbrook, *The Supreme Court 1983 Term; Foreword: The Court and the Economic System*, 98 Harv.L.Rev. 4, 10-12 (1984).

Footnote No. 186

A new pipeline can be built in one to four years. Stewart Trans. at 2526.

Footnote No. 187

See Schuykill Energy Resources, Inc. v. *Pennsylvania Power & Light Co*., 113 F.3d 405 (3d Cir. 1997) (rejecting as speculation claims about competitive conditions in electricity markets in the year 2001).

Footnote No. 188

Edison and other intervenors contend that the merged entity could raise the costs of rival gas-fired generation plants by manipulating the windows into the SoCalGas transportation system to force re-routings or renominations of gas supplies. We conclude, however, that SoCalGas lacks the ability to impose such costs with the "surgical precision" alleged by these intervenors. As the applicants point out, "there is no significant or persistent advantage to be gained [for UEGs] by buying at one location over the others." Leitzinger Rebuttal at 26. In fact, when SoCalGas imposes Rule No. 30 restrictions, customers may still deliver up to the sum of 110% of their expected daily usage plus their firm storage injection rights. Stewart Rebuttal at 6. Thus, overnominations have not caused any plant to curtail operations within the past several years. Hieronymous Rebuttal at 8.

Footnote No. 189

To preclude the transfer of "inside" information, the applicants have also agreed to maintain an interactive EBB reservation and information system for its gas transportation network which would report all significant operational data, including maintenance and system status information. In addition, SDG&E will separately nominate and schedule its UEG volumes over the EBB and obtain CPUC approval before providing transportation discounts to any affiliates. Finally, groups responsible for gas operations will operate independently of gas acquisitions and marketing groups and of SDG&E employees providing "electric merchant functions."

Footnote No. 190

The Southern California Public Power Authority contends that the merger will adversely affect competition within an alleged "BTU" product market. Sinclair Direct at 21. The Power Authority fails, however, to provide any evidence of a significant cross-elasticity of demand between electricity and gas. *See United States* v. *E.I. du Pont de Nemours & Co.*, 351 U.S. 377, 404 (1956). In fact, there is a significant cost difference between gas and electricity for those applications where substitution is theoretically possible. Hieronymous Rebuttal at 32. Moreover, evidence that the two resources are jointly marketed is wholly inconclusive, and may suggest that they are actually *complements*. We conclude that a significant "gap" exists in the "chain" between these two hypothetical substitutes, and that "BTUs" is not a cognizable relevant product for purposes of reviewing this merger.

Footnote No. 191

Yap Direct at 32.

Footnote No. 192

Yap Direct at 34.

Footnote No. 193

Leitzinger Rebuttal at Exhibit JJL-2.

Footnote No. 194

In fact, because the procurement activities of the two companies will not be combined, market share statistics overstate the market power of the combined entity. *See* Leitzinger Rebuttal at 28.

Footnote No. 195

Until recently, PUC rules prohibited the companies from competing for sales to core customers. Hieronymous Rebuttal at 30.

Footnote No. 196

Hieronymous Rebuttal at 30.

Footnote No. 197

Id.

Footnote No. 198

Hieronymous Rebuttal at 31.

Footnote No. 199

Id.

Footnote No. 200

Stewart Trans. at 2781.

Footnote No. 201

Brodley, *Potential Competition under the Merger Guidelines*, 71 Cal. L.Rev. 376, 378 (1983). Areeda and Hovenkamp also question the doctrine as a basis for a section 7 violation. Areeda and Hovenkamp, *Antitrust Law* § 1118 (1996 Supp.).

Footnote No. 202

Marine Bancorporation, *supra*, at 630-32.

Footnote No. 203

See Yap Direct at 48, 55; Taylor Direct at 53. *But see* Stewart Rebuttal at 32 (noting that SDG&E loads are increasingly fragmented).

Footnote No. 204

Tenneco v. *FTC*, 689 F.2d 346 (2d Cir. 1982). *See B.A.T. Indus.*, 104 F.T.C. 852 (the "best evidence . . . is likely to be subjective").

Footnote No. 205

See BOC Int'l Ltd. v. *FTC*, 557 F.2d 24, 29 (2d Cir. 1977)(rejecting a finding of "eventual" entry as "uncabined speculation").

Footnote No. 206

Republic of Texas Corp. v. *Board of Governors of the Fed. Reserve Sys*., 649 F.2d 1026, 1047 (5th Cir. 1981) (demonstrating entry in the "reasonably foreseeable future" was insufficient); *BOC Int'l*, *supra*, 557 F.2d at 29.

Footnote No. 207

Tenneco, *supra*, at 355; Merger Guidelines §4.11.

Footnote No. 208

Exhibit 385 at Response to Request 6.16.

Footnote No. 209

Id.

Footnote No. 210

Yap Direct at 53.

Footnote No. 211

Yap Direct at 184.

Footnote No. 212

The anchor tenant theory advanced by some intervenors, although presented as a potential competition question, essentially alleges that the merger will vertically "foreclose" opportunities for Kern River and other competitors in the intrastate gas transportation market. The issue may have been reframed because the courts view foreclosure allegations in vertical merger cases with considerable skepticism. *See Alberta Gas Chems*. v. *E.I. du Pont de Nemours*, 826 F.2d 1235, 1244 (3d Cir. 1987) *cert*. *denied*, 486 U.S. 1059 (1988); 4 Areeda & Turner, *Antitrust Law* par. 1004, at 211 (foreclosure argument has "grave weaknesses").

Footnote No. 213

Yap Direct at 61.

Footnote No. 214

Taylor Direct at 35.

Footnote No. 215

Mercantile Texas Corp. 638 F.2d at 1267. *See also U.S*. v. *First National State Bancorporation*, 499 F.Supp. 793, 814 (D.N.J. 1980).

Footnote No. 216

Hieronymous Rebuttal at 42-43.

Footnote No. 217

Hieronymous Rebuttal at 43.
