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# Transcript Exhibit(s)

Docket #(s): RE-00000C-94-0165

E-01345A-97-0773

E-01345A-98-0473

Exhibit # : APS13, APS14, APS15, Hearing Officer1, Commonwealth5

BEFORE THE

ARIZONA CORPORATION COMMISSION

REBUTTAL TESTIMONY OF WILLIAM H. HIERONYMUS

On Behalf of

Arizona Public Service Company

Docket No. E-01345A-98-0473
Docket No. E-01345A-97-0773
Docket No. RE-00000C-94-0165

July 12, 1999

EXHIBIT
Admitted
APS-13

## I. INTRODUCTION

**Q. Please state your name and business address.**

A. My name is William H. Hieronymus. My business address is PHB Hagler Bailly, Inc., One Memorial Drive, Cambridge, Massachusetts 02142.

**Q. By whom are you employed?**

A. I am Senior Vice President of PHB Hagler Bailly, Inc., the commercial consulting subsidiary of Hagler Bailly. Hagler Bailly is a worldwide provider of consulting, research and other professional services to corporations and governments on energy, telecommunication, transportation and the environment.

**Q. What is your educational background and work experience?**

A. I received my Bachelor's degree from the University of Iowa in 1965, my Master's degree in economics in 1967 and a Doctoral degree in economics in 1969 from the University of Michigan, where I was a Woodrow Wilson Fellow and National Science Foundation Fellow. After serving in the U.S. Army, I began my consulting career. In 1973, I joined Charles River Associates Inc. as a specialist in antitrust economics. By the mid-1970s my focus was principally on the economics of energy and network industries. In 1978, 1 joined Putnam Hayes & Bartlett, Inc., where my consulting practice has focused almost exclusively on network industries, particularly electric utilities. Putnam, Hayes & Bartlett, Inc. merged with Hagler Bailly, Inc. in 1998.

During the past 25 years, I have completed numerous assignments for electric utilities; state and federal government agencies and regulatory bodies; energy and equipment companies; research organizations and trade associations; independent power producers and investors; international aid and lending agencies; and foreign governments. While I have worked on most economics-related aspects of the utility sector, a major theme has been public policies and their relation to the operation of utility companies.

Since about 1988, the main focus of my consulting has been on electric utility industry restructuring, regulatory innovation and privatization. In that year, I began work on the restructuring and privatization of the electric utility industry of the United Kingdom, an assignment on which I worked nearly full time through the completion of the restructuring in 1990. I also led a major study of the reorganization of the New Zealand electricity sector, focusing mainly on competition issues in the generating sector. Following privatization of the U.K. industry, I continued to work in the United Kingdom for electricity clients based there and I was also involved in restructuring studies concerning the former Soviet Union, Eastern Europe, the European Union and specific European countries.

Late in 1993, 1 returned to the United States, where I have worked on restructuring, regulatory reform and, increasingly, the competitive future of the U.S. electricity industry. In this context, I have testified before FERC and state commissions on market power issues concerned with several mergers, power pools and market rate applications. More generally, I have testified before state and federal regulatory commissions, federal and state courts and legislatures on numerous matters concerning the electric utility and other network industries. This includes testimony before the ACC on several occasions. My resume is included as Attachment WHH-1.

## II. PURPOSE AND SUMMARY OF TESTIMONY

### Purpose

**Q. What is the purpose of your testimony?**

A. The purpose of my testimony is to respond to those parts of the testimony of Enron witness, Mark W. Frankena that address APS. The essence of Dr. Frankena's testimony is that APS includes two load pockets in which APS and/or APS and SRP will have market power. Moreover, he asserts that there may be other areas in which APS or other utilities in

Arizona may have market power due to concentration of ownership of facilities that can serve load in those areas, though he concedes that he has done no analysis to identify such areas. Lastly, he asserts that nothing in the APS settlement agreement would fully prevent or mitigate APS's ability to exercise market power.

In my testimony, I discuss the regulatory mechanisms that will preclude APS from exercising market power in its load pockets. I also present an analysis that I have performed that looks at APS's market power outside of the load pockets.

**Summary of Conclusions**

**Q. Please summarize your conclusions regarding APS's load pockets.**

A. After APS's generating assets are transferred to a Pinnacle West generation subsidiary (hereafter, "Genco"), Genco will be a wholesale seller of power subject to FERC jurisdiction. APS intends that Genco will be an "Exempt Wholesale Generator", generally authorized to sell power at market based rates. Dr. Frankena notes correctly that portions of APS's territory are load pockets. These load pockets exist today, and are neither caused by or exacerbated by the proposed settlement. FERC will not grant market rate authority under circumstances where the seller has market power. FERC has previously found that load pockets can create market power and required that it be mitigated, fundamentally, by restricting the ability of the generator to sell at market rates in load pockets so that market power cannot be exercised when transmission constraints substantially narrow the range of competitive suppliers to retailers selling to customers in the pockets.

FERC has used a variety of means to control load pocket-related market power. APS informs me that its intent is to file cost-based tariffs for units that are "must run" due to load pocket constraints. This is similar to the procedure that FERC has accepted for must run units in California. APS will be required to sell power from these facilities at tariff rates. Entities selling power at retail within the load pockets, including APS and APSES, will be required to buy a portion of their energy at these tariff rates. The charge for capacity to serve customers in the load pockets, insofar as such capacity must be from units within the load pocket, is included in the distribution charges filed as part of the proposed settlement; retail sellers will not have to pay market-based capacity charges for these units. Assuming that FERC finds this approach acceptable, it will assure that APS's prices for power from these units are just and reasonable and reflect their cost of service.

**Q. What do you conclude concerning Dr. Frankena's conjecture that APS may have market power outside of the load pockets?**

A. I have examined whether Genco will have market power in its service area, other than under load pocket conditions. The methodology that I have used is the methodology specified in FERC's Merger Policy Statement, dated December, 1996. This methodology is FERC's implementation of the Merger Guidelines of the Departement of Justice and Federal Trade Commission, the two federal antitrust enforcement agencies. Based on this analysis, I conclude that the market structure of sellers of energy to customers located in APS's service area is workably competitive and that, according to the standard criterion, Genco will not have market power either acting alone or in tacit collusion with other sellers. Since Genco lacks market power in the area in which its facilities are located, it also will not have market power in any larger markets. As discussed below, the principal reasons why APS lacks market power are a) owners other than Pinnacle West own the majority of generation in the northern and central Arizona area, and b) that substantial inbound transmission capability allows wholesale customers serving retail loads in the area to buy substantial amounts of power from out-of-state generators.

## III. MARKET POWER IN LOAD POCKETS

**Q. What is a load pocket?**

A. A load pocket is a geographic area in which the peak load exceeds the capability of the transmission system to allow power imported from outside the pocket to fully and reliably serve load. Usually, this limit is the thermal limit of the transmission lines entering the pocket. Since imports cannot fully meet load, it is necessary that some part of the load must be met by running generation located within the pocket. Other concerns, such as system stability and voltage problems, may also dictate that generation within the pocket must be run.

**Q. Why do load pockets create market power concerns?**

A. This is because only generation within the load pocket can meet the load that exceeds the import limit. If there is only one, or very few owners of generation in the pocket, and the prices that they charge are not regulated, the owner(s) may be able to charge excessive prices. This will be true even if the market in the area surrounding the pocket is competitive. For example, assume that the peak load in the pocket is 2,000 MW and the ability to import energy is limited to 1,800 MW. Assume also that the outside market is competitive. So long as load is below 1,800 MW, which will be the case in most hours, the price of power delivered into the pocket will be competitive. Even when load is above 1,800 MW, retail sellers serving 1,800 MW of load would be able to access the competitive outside market. However, the retail sellers of the last 200 MW would have to buy from generation inside the pocket. If there is a single seller, it will be able to charge very high prices in these few hours, since it will face no competition. If there are very few potential sellers inside the pocket there is a concern that they will tacitly collude to raise prices. This is especially likely if meeting the last 200 MW of load requires the generation from more than one potential seller.

**Q. Are there load pockets within the APS service area?**

A. Yes. APS's 'Must Run' Generation Report, which was provided to Enron and is attached to Dr. Frankena's testimony, shows three load pockets:

- **The Valley (Phoenix).** The 1998 peak load (forecasted in late 1997) is 6,983 MW and the thermal limit on imports is 6,180 MW. At least some APS and SRP generation inside the valley is required to meet load for 460 hours per year; stability and voltage concerns are shown to add about 200 hours per year in which some in-valley generation must be run. There are 1,948 MW of generation in the valley, all of which is owned by either APS or SRP. APS's Ocotillo and West Phoenix stations are must run during some hours.

- **Yuma.** Yuma load is approximately 250 MW. Transmission is limited to 175 MW. Transmission contingencies require that generation from APS's Yucca CTs, the only generation inside the pocket, must run whenever load exceeds 135 MW. This occurs in 2,744 hours per year.

- **Douglas.** Douglas is served radially by a single 115 kV transmission path. In the event that of an outage on that line, load can be met only by runningAPS's Douglas CT. APS's study estimates that this will occur for less than one hour per year.

**Q. Does the existence of these load pockets mean that Genco could exercise market power in its pricing of the output of its in-pocket generating units?**

A. In the case of the Yucca and Douglas CTs it would be able to charge above competitive prices during those hours when the units are must run in the absence of regulation. In the case of the valley units, APS competes with SRP, and SRP has sufficient generation in the valley that APS generation is not required. However, with only two sellers to meet the roughly 1,000 MW of peak load that cannot be met with imports, there may be a concern that the prices charged for in-valley generation will not be competitive.

**Q. Could generation divestiture create competitive markets within the load pockets?**

A. No. In the cases of Yuma and Douglas, there is only a single generating station inside the pocket. Divestiture might make the valley market more competitive, but only if a major portion of SRP's generation was divested. APS does not own sufficient generation to meet the needs of the load pocket. Moreover, all of its generation is only at two stations. Finally, since more than half of the in-valley generation is needed at peak load times, even the sale of one of APS's stations (creating a new competitor) would leave at most two generators competing at the margin to met valley loads.

**Q. Will the planned generation additions at West Phoenix exacerbate the load pocket market power problem?**

A. No, quite the contrary. The new combined cycle capacity likely will be in merit during all hours when load exceeds transmission capability. This will reduce pressure on the transmission system. Further, Calpine will be a new entrant into the valley; it will sell its share of the new capacity on its own account. While this is not, by itself, sufficient to ensure that the market is competitive, it does mean that during at least a part of the hours in which the existing generation is must run that there will be an additional competitor to meet a part of the load. Because SRP is the dominant generator inside the valley, adding to APS's capacity and adding Calpine as a generator will reduce the concentration of the in-valley market.

**Q. Are you aware of any planned future events that are likely to impact the severity of the valley load pocket?**

A. APS informs me that it plans to increase transmission capability into the valley with expanded transmission from Palo Verde to Estrella. It also believes that SRP is planning to expand transmission into the eastern part of the valley. Expanding transmission will reduce the number of hours during which the valley is a load pocket.

**R. Please explain why APS will not be able to exercise market power in its pricing of generation within the load pockets.**

A. APS' wholesale power sales are subject to FERC jurisdiction. FERC will not grant market rate authority (the right to sell at unregulated prices) under circumstances where it finds that the generator is likely to have market power. Where load pockets create market power, FERC has not granted market rate authority in respect of sales when and where the load pocket is constrained, but instead has required that market power be mitigated.

**Q. Can you identify specific instances where FERC has required such mitigation?**

A. Yes. There are three instances in which I was personally involved in which FERC required mitigation of load pocket-related market power. The first was in California. Each of the three large IOUs in California had load pockets in which specific generating stations, or a proportion of the generation owned by a single company, were must run due to transmission constraints. A second case is in NEPOOL, the power pool serving New England. There are a number of potential load pockets within NEPOOL. Pricing rules, applicable to all generation within a constrained area were required as a stand-by and automatically applicable mitigation of market power. The third was in New York, where load pockets were identified within Niagara Mohawk and Consolidated Edison's service areas. For Con Edison, in which the City of New York is a major load pocket requiring that up to 5,000 MW of in-City generation must run during peak hours, capacity must be sold at tariff prices and energy must be sold at either tariff rates or, in the case of generation that runs frequently during non-must run periods, must be bid into the New York Power Exchange at a bid price that is no higher than in like periods when it is not must run.

**Q. Do the market power mitigation measures that the FERC has required in these cases lapse if the utility that historically has served the load pocket divests its generation?**

A. No. The must run status of the units does not depend on ownership, but rather is inherent to the generating stations. Indeed, most of the must run generation in both New York and California has been divested, but the market power mitigation remains fully in effect.

**Q. Can you explain more fully how the market power mitigation for the New York City load pocket works?**

A. Yes. All entities serving load in New York City must purchase a portion of their capacity and energy from in-City units. The owners of that capacity (previously Con Edison, now three other generators) must sell capacity at a tariff rate that is based on Con Edison's cost of service rate computed using only the book value of its in-City generation. For units that run only in hours when the City is not constrained, energy is also sold at a cost of service rate. For lower cost units that do run when the City is not constrained and prices are set in the larger New York State market (which FERC has found to be workably competitive), the owners are allowed to bid prices in constrained periods that are no higher than the prices that they bid in unconstrained periods during which their generation was in merit. The energy price that they receive is the in-City market price, not their bid price. Since all in-City units are subject to mitigation, this energy price will be the variable cost of the most expensive unit that is required to meet in-City load.

**Q. How did FERC mitigate load pocket market power in California?**

A. In California, the ISO designates which units are must run do to transmission constraints or other factors. Must run units are compelled to enter into contracts with the ISO. While there are various types of contracts that differ principally in terms of the accounting for revenues earned when the units are not must run, the basic structure of the contracts is cost of service. The ISO pays a demand charge that covers the fixed cost of the units and buys energy at a variable cost rate.

**Q. Will FERC require market power mitigation forAPS's units in its load pockets?**

A. Yes, most assuredly. APS has made no secret of the must run character of these units and FERC will require that measures be put in place that assure that market power will not be exercised. Indeed, APS plans to file tariffs, either asamendements to its Open Access Transmission Tariff, or as part of the AISA tariff filing, that will mitigate its market power.

**Q. Will FERC impose the same type of mitigation that it required in New York or California on APS's must run units?**

A. No, not precisely. The California mitigation mechanism requires that an ISO is in place. The New York mechanism requires that there is a power exchange with location-specific pricing. Neither can be adopted directly for Arizona, since there is neither a ISO nor a power exchange. However, the same concepts can be employed in a slightly different form and are included in APS's planned filing.

**Q. How can similar mitigation of load pocket-related market power be implemented in the absence of an ISO and/or power exchange?**

A. Yes. The simplest way to do this is to require that the capacity and energy from must run units be sold at cost-based rates, effectively barring them from participation in market-based pricing. This is what FERC has done for New York City capacity and for energy from units that only run when the load pocket is constrained. This also is the essence of the California Must Run Agreements. While the California agreements are contracts with the ISO, the same could be accomplished with a tariff, provided at all sellers into the load pocket are required to purchase a like proportion of energy at the tariff rate.

**Q. What does APS plan to propose as mitigation of the potential market power of its existing generation in the load pockets?**

A. The planned proposal for mitigation of load pocket market power is described in the draft Must-Run Protocol of the AISA. In brief, the AISA proposal, with which APS concurs, defines four load pockets: APS valley, SRP valley, Yuma and Tucson. The existing generation within the load pockets is defined as Must Offer generation. The owners of that generation must offer to sell their output on a variable cost basis in amounts sufficient to satisfy the aggregate must run requirement for the load pocket. Schedule Coordinators (SCs) that aggregate the loads and resources of all Energy Service Providers (ESPs), selling in the load pockets, including APS as a provider of last resort and APSES as a competitive retailer, will be required to take the same proportion of their capacity and energy from the relevant must run units.[1] SRP will have an equivalent, though initially not identical, form of mitigation of its potential market power within the load pocket.

**Q. Will retailers serving load in the load pockets have sufficient access to transmission that they will need to purchase only their pro rata share of must run capacity and energy from generation located inside the load pocket?**

A. Yes. Initially, all SCs will have pro rata entitlements to transmission capacity into the load pocket. Ultimately, SCs will be allowed to trade entitlements among themselves and their must run requirements will be adjusted accordingly.

**Q. How will the capacity of the must run units be priced?**

A. APS has included the capacity cost of the must run units, (limited to the percentage of each must run generating unit's annual usage that is attributable to providing must run generation service in its distribution rates.

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[1] Schedule Coordinators can, in the alternative, 1) contract for discretionary local generation, 2) curtail interruptible load or 3) (in the case of the valley) contract for additional transmission into the load pocket from another transmission service provider (i.e. SRP). Ultimately, but not initially, Schedule Coordinators will be able to meet their must-run requirement by purchasing transmission rights from other Schedule Coordinators.

**Q. To the extent that ancillary services must be provided from generation inside of the load pockets, what assurance will there be that market power will not be exercised in providing them?**

A. Ancillary services will continue to be provided by APS, as a transmission provider under tariffs that comply with FERC's Order 888 and that will be administered by the AISA.

## IV. GENCO MARKET POWER OUTSIDE OF LOAD POCKETS

**Q. How have you addressed Dr. Frankena's concern acceptance of the provisions of the settlement agreement that transfer APS's generation to an EWG could result in market power outside of the load pockets that you have discussed?**

A. Dr. Frankena conjectures that "further investigation may show that there are additional relevant geographic markets for capacity and energy larger than the load pockets just discussed but still small enough so that APS, SRP and TEP would have substantial shares and concentration would be high." He concedes that he has made no analysis of this but presents data on transmission that suggests that transmission limits and congestion may create such submarkets.

**Q. Have you performed an analysis to test whether APS is likely to have market power in areas of Arizona outside of the load pockets?**

A. Yes.

**Q. Please explain the basis for your analysis.**

A. I have used the framework that normally is used for investigating mergers to analyze the market structure relevant to the provision of energy to customers located in the area served by SRP and APS. The specific framework is derived from FERC's Merger Policy Statement which, in turn, is intended by FERC to implement the U.S. Department of Justice's and Federal Trade Commission's Merger Guidelines.

**Q. Since this is not a merger, why have you used a merger-related analytic standard to investigate APS's potential market power?**

A. Antitrust enforcement to limit abuses of market power normally is on a reactive basis after an abuse has been alleged. The merger standards are the only available basis for judging the competitiveness of markets on a before-the-fact basis.

**Q. Please explain how the merger standards analyze market power.**

A. An analysis of market power begins with the definition of relevant geographic and product markets. A geographic market is defined by the antitrust authorities as a market in which a hypothetical monopolist could profitably sustain a price significantly above competitive levels. In its implementation of this definition the FERC has retained its prior definition of "destination markets" in which each utility control area is presumed to be a relevant market. However, parties are entitled to justify larger or smaller markets.

The relevant product markets are defined by the ability of consumers and producers to switch between the product in question and other products. Electricity is assumed by FERC to lack close substitutes. Moreover, it defines separate products comprising electricity: electric energy, capacity, and the various ancillary services.[2] Because electricity cannot readily be stored, FERC recognizes that market conditions may vary by season and/or day part (i.e. on-peak and off-peak) and requires analysis of market conditions by time of day.

Ultimately, the market power question is whether a firm, or group of firms acting independently (but taking into account the interdependence of their actions and the responses of competitors) can profitably sustain prices that significantly exceed the competitive level. In a merger context, the question is whether the combination of the merging firm makes the exercise of such market power significantly more likely. Here, the question is somewhat different: will the utilities in Arizona (and for purposes of my testimony, APS specifically) be able to charge super-competitive prices if their generation prices cease to be regulated on a cost-of-service basis?

The primary framework used by the antitrust agencies and FERC for assessing the likelihood that market power will exist or be enhanced is an analysis of market structure. Concentrated markets, wherein supply is dominated by one or a few firms, are deemed to be conducive to the exercise of market power. Unconcentrated markets are deemed not to be problematic. Hence, the main purpose of a market power analysis is to determine the extent to which the supply of a product to customers in a defined geographic market is concentrated.

**Q. How is concentration measured?**

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[2] Because ancillary services are provided as a regulated element of transmission service, ancillary services markets are not examined in the context of utility mergers.

A. The current measure of concentration used by both FERC and the antitrust agencies is called a Herfindahl-Hirschman Index (HHI). The HHI is simply the sum of the squares of the market shares of suppliers. A monopoly market has an HHI of 10,000. A market with 10 equal-sized participants has an HHI of $10*(10)^2 = 1000$. In evaluating mergers, the focus is on the amount by which the HHI increases as a result of the merger. In considering the competitiveness of a market outside of a merger context, it is the level of the HHI that matters.

**Q. What level of HHI is considered to represent a workably competitive market?**

A. There is no single answer to this question that is generally applicable. However, the Justice Department has recommended, and FERC has tacitly adopted, the standard that in considering whether to deregulate prices in previously regulated industries, an HHI of 2,500 is acceptable, as is noted by Dr. Frankena on page 41 of the article that he attached to his testimony.

**Q. Have FERC or the antitrust agencies adopted measures that address the market shares of large sellers in a market?**

A. Yes. As noted by Dr. Frankena, FERC generally has used a threshold of a market share below 30 percent in determining whether to grant a wholesale supplier the right to sell at market, rather than regulated prices. The Merger Guidelines state that a merger resulting in a firm with a share of 35 percent or more will be subject to review.

**Q. How have you implemented this guidance in your analysis of whether APS will have market power?**

A. I have focused on the market structure for electric energy, the predominant market that is reviewed by FERC. Consistent with FERC's requirements in mergers, I have examined market structure under supply conditions applicable to different times of the year (i.e. by season and time of day).

The geographic market that I have focused on is the area served by APS and SRP. APS informs me that the SRP and APS control areas are so intertwined that it is not practicable to identify meaningful transmission limits that might divide them.[3]

FERC's analysis of energy markets uses the concept of "deliverable economic capacity". Deliverable economic capacity is defined as potential supply that can be delivered to a destination market (i.e. the APS/SRP area) both physically and economically. By economically, it means that the busbar variable cost of production, adjusted for losses and transmission tariffs, does not exceed the price in the destination market. By physically, it means that the aggregate of such supplies imported into the area cannot exceed the transmission capability into it. Thus, the potential supply considered in evaluating market structure consists of all economic supplies located within the area, plus the aggregate of economic supplies up to the amount of the transmission limit.

In determining market structure, the allocation of this inbound transmission capability matters, since not all economic capacity is able to access the market simultaneously. The proration of available transmission capability is accomplished using a model. In essence, the model allocates each defined transmission interface proportionately among all

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[3] Formally, I modeled the APS control area with unconstrained transmission between SRP and APS. This means that there is a transmission charge and line losses that reduce SRP's share of the market and, therefore, increase APS's share.

economic supplies that can reach it. For example, suppliers in the Pacific Northwest have pro rata shares of the capacity into northern California and of the DC tie linking to southern California. Supplies that can reach northern California are pooled with economic generation located in northern California and receive proportionate shares of the link between northern and southern California. These are pooled with the energy coming down the DC tie and with the economic energy produced in southern California. This pool of economic capacity shares, pro rata, the links between southern California and the desert southwest. This is pooled, again, with the power located in the relevant part of the desert southwest (e.g. Palo Verde, Navajo or Marketplace) and receives a pro rata share of the transmission into the APS/SRP area. Thus, by the time it reaches the APS, the power from the Pacific Northwest has been "squeezed" progressively through several interfaces and also attracted transmission charges and line losses. The end result is that essentially none of it counts as deliverable to APS/SRP. Conversely, power that is located closer to APS/SRP is squeezed fewer times and receives lower transmission charges and line losses. A substantially higher proportion of it reaches, and counts as potential supply to, the APS/SRP market.

**Q. How did you define what generation is inside the APS/SRP area?**

A. All generation owned by APS and SRP is considered within the APS/SRP area except for Palo Verde, Navajo and Four Corners. Each of these stations is a separate node on the transmission system with a defined maximum capability to sell into the APS/SRP area.

**Q. How did you define the capacity of the transmission system?**

A. Transmission capability was defined as the total transfer capability (TTC) taken principally from OASIS web sites of the various utilities and the California ISO.[4] I usedTTCs rather than ATCs because the transmission reservations of integrated utilities to bring their shares of the jointly owned stations will no longer apply.

This requires a brief explanation. At present APS has, for example, firm transmission rights from Four Corners to its service area. After APS's generation is transferred to Genco, the Genco will no longer be assured of a firm transmission path to APS. Rather, it will have to compete with other owners of capacity at Four Corners, as well as imports that can reach the Four Corners node from Marketplace, PNM and the Navajo node for the transmission capability into APS/SRP.

**Q. What is the transmission capability into APS/SRP that is defined in the model?**

A. The inbound transmission paths are: Four Corners to APS, 1340 MW; Navajo to APS, 2264 MW; Palo Verde to APS, 3810; TEP to APS/SRP, 1344 MW; and WAPA to SRP, 450 MW. These links, together with the other links in the model, are shown on Attachment WHH-2.

**Q. What price levels do you assume are market prices in the APS/SRP area for purposes of defining deliverable economic capacity?**

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[4] ATCs are used outside of California, Arizona and New Mexico. In cases where desert southwest utilities have shares of remote units located outside of this region, such as SRP's share of Craig, Mohave and Hayden, the share of the unit is moved into their service area, since the ATC has been reduced to reflect their firm entitlements.

A. In order to assure that I am examining the market structure over the full range of market conditions, I examined deliverable economic capacity at prices ranging between $55 per MWh for the summer super-peak down to $10 per MWH for the spring/fall off-peak hours. In 1998 the highest monthly on-peak price at Palo Verde reported by Dow Jones was $48 per MWh and the summer average was $42 per MWh. The off-peak summer/fall prices averaged about $14 per MWh.

**Q. Does you analysis take new construction into account, including the announced new AEP capacity to be built at West Phoenix?**

A. I have performed two analyses. The first includes only that generation that exists today. A second analysis, which I call a 2001 analysis, includes most but not all of the new generation scheduled for completion by approximately the end of 2001. The new generation included in this latter analysis is shown on Attachment WHH-3. Note that this includes both the Phase I expansion at West Phoenix (130 MW owned solely by Genco) and the Phase II expansion (500 MW split between Genco and Calpine).

**Q. You stated that you included "some but not all" announced new generation. Why did you not include all of it?**

A. Several projects have been announced at locations near the California-Arizona or California-Nevada borders. I discussed these with APS's system planners and decided that it would not be realistic to include all of them. Excluding some of these projects is conservative; had I included all of them, the APS market would have been less concentrated and APS's share would have been smaller. I should note that while I have included some of these projects by name and excluded others, this does not reflect a specific conclusion that these are the specific projects that necessarily will be built.

**Q. What did you use for transmission losses?**

A. Losses were assessed at 2.8 percent per wheel.[5] Note that wheels are defined, hence losses are computed, for movement between nodes. Hence, power that moves from southern California to Palo Verde to APS is assumed to have losses of 5.6 percent.

**Q. What did you use for transmission tariff rates?**

A. Posted rates were used for all but California utilities. Based on discussion with personnel at the California ISO, we used the OATT rates for the exit utility (usually, SCE) as the transmission charge for through and out service from California.

**Q. What exhibits show the results of your analyses?**

A. The results of the analysis are summarized on Attachment WHH-4. Prices are reported for Super Peak (APS's highest 150 load hours in each season), Peak (the remainder of daytime weekday hours) and Off Peak (remaining hours) for each of three seasons. The seasons are summer, winter, and shoulder (spring and fall). The supplier report, showing the individual shares for each supplier in each time period, are shown on Attachments WHH-5 for the 1999 analysis and WHH-6 for the 2001 analysis. The abbreviations used in the supplier reports are defined on Attachment WHH-7. Attachments WHH-8 and

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[5] In its April, 1999 Notice of Proposed Rulemaking, FERC suggests using 3.0percent per wheel. The 2.8 percent factor was derived from reviewing a sample of loss factors from OATT tariff filings.

WHH-9 show the transmission path reports for the 1999 and 2001 analyses. These reports show the line ratings and the flows on the lines into the APS market.

**Q. What are the conclusions of your analyses?**

A. As is shown on Attachment WHH-4, in the 1999 analysis, the market has an HHI of about 1200. This level of HHI is characterized by the antitrust agencies as only moderately concentrated. The level of concentration is only about half of the maximum acceptable in the context of price deregulation. By any reasonable measure, this is a workably competitive market, and participants should be able to charge unregulated prices. There is relatively little difference among seasons.

APS's share of the market is about 23 percent. This is within the range that FERC finds acceptable for granting market rate authority and well below the antitrust authorities' 35 percent threshold for investigating single firm market power.

The 2001 analysis shows similar results. The market is slightly less concentrated as a result of new entry. APS's market share is slightly higher (by less than 1 percentage point) as a result of its 380 MW of new generation.

## V. Pricing in the WSCC: the California Factor

**Q. Are there any other factors that you believe should be brought to the Commission's attention that relate to the market power issue?**

A. Yes. The analysis that I have just discussed assumes that APS/SRP is a market. However, pricing in the desert southwest region cannot properly be understood without taking into account the influence of California. California is a big power "sink". Most of the time, California must import power to keep the lights on. All of the time it imports power on an economic basis. Arizona is connected to California by a very broad transmission "highway". This highway is rarely constrained. Moreover, the highway can be used to move power from California and beyond into Arizona if there is economic reason to do so.

Generators in Arizona can elect to sell power in Arizona or into California. If the price that they receive from California (taking into account transmission costs and line losses) is higher than they would earn in Arizona, they will sell into the California market. Similarly, if the Arizona price is higher, they will not export to California but will sell locally. Indeed, if the Arizona price rises above the California price by enough to cover transmission costs, the power flow will reverse. This arbitrage between markets means that under normal circumstances, power prices in Arizona will be "net back" from the California price.

Thus, prices in Arizona are not independent of prices in California. The same is true, to only a somewhat lesser degree, to the relationship between prices in California and the Pacific Northwest. Hence, the ability to raise prices in Arizona (and the non-load pocket portions of APS/SRP) will generally require the ability to raise prices in a far larger market, consisting at a minimum of the desert southwest and southern California. In this big pond, APS is a very small fish.

A second consideration relates to the type of generating plant that Genco will control. During the on-peak hours when markets generally are believed to be most prone to the exercise of market power, prices are set based on the cost of running gas steam units. Again this is because of the net back situation concerning California. The opportunity cost of Arizona generators (as can be quantified by the Palo Verde market hub price) will be based on the cost of gas-steam generation in the majority of hours. Most of Genco's capacity is either baseload coal or nuclear. It has little capacity that is nearly marginal at these prices and most of the near-marginal capacity that it does have will be must run. Hence, there is little capacity available to it that could be cheaply withdrawn from the market in order to drive up the price.

## VI. Conclusions

**Q. Can you please summarize your conclusions with respect to the concerns expressed by Dr. Frankena?**

A. Yes. Dr. Frankena's first concern was that Arizona utilities would have market power in load pockets. The load pocket issue does not arise from the proposed settlement which does not, on its face, deal with the pre-existing load pocket problem. His concern that market power could exist in the absence of regulation that constrains its exercise is valid. However, he ignores the fact that wholesale sales will remain subject to FERC jurisdiction and that FERC will not permit market rates to be charged by firms that possess market power in load pockets. I have reviewed the proposed method for controlling such market power and find that it eliminates the ability and incentive of APS to seek to exercise market power by raising the prices charged in the valley and in Yuma when the areas are constrained. Hence, while he has identified a legitimate issue, there are specific mechanisms for solving it that are fully effective.

His second concern was that there might be other areas surrounding the load pockets where market power might be exercised. I have investigated the structure of the APS/SRP market area, the area in which APS would be most likely to have market power outside of the previously discussed load pockets. I found that the market structure is sufficiently unconcentrated to support price deregulation. I also found that APS's market share is low enough to eliminate the expectation that APS will be able to exercise market power.

**Q. Does this complete your testimony?**

A. Yes, it does.

**WILLIAM H. HIERONYMUS** **Senior Vice President**

William Hieronymus has consulted extensively to managements of electricity and gas companies, their counsel, regulators and policy makers. His principal areas of concentration are the structure and regulation of network utilities and associated management, policy and regulatory issues. He has spent the last several years working on restructuring and privatization of utility systems internationally and on changing regulatory systems and management strategies in mature electricity systems. In his twenty-plus years of consulting to this sector he also has performed a number of more specific functional tasks including the selection of investments, determining procedures for contracting with independent power producers, assistance in contract negotiation, tariff formation, demand forecasting and fuels market forecasting. Dr. Hieronymus has testified frequently on behalf of utility clients before regulatory bodies, federal courts and legislative bodies in the United States and United Kingdom. Since joining Putnam, Hayes & Bartlett, Inc. (PHB) (which merged with Hagler Bailly, Inc. in 1998) he has contributed to numerous projects, including the following:

## ELECTRICITY SECTOR STRUCTURE, REGULATION AND RELATED MANAGEMENT AND PLANNING ISSUES

### U.S. Assignments

- Dr. Hieronymus served as an advisor to an electric utility on restructuring and related regulatory issues and has worked with senior management in developing strategies for shaping and adapting to the emerging competitive market in electricity. As a part of this general assignment he has testified respecting, a settlement with the state regulatory commission staff that provides, among other things, for accelerated recovery of strandable costs. He also prepared numerous briefings for the senior management group on various topics related to restructuring.

- For several utilities seeking merger approval he has prepared and testified to market power analyses at FERC and before state commissions. He also has assisted in discussions with the Antitrust Division of the Department of Justice and in responding to information requests. The analyses he has sponsored cover the destination market-oriented traditional FERC tests, Justice Department-oriented market structure tests similar to the Order 592-required analyses, behavioral tests of market definition or of the ability to raise prices and examination of vertical market power arising from ownership of transmission and generation and from ownership of distribution facilities in the context of retail access. The mergers on which he has testified include both electricity mergers and combination mergers involving electricity and gas companies.

- For utilities seeking to sell or purchase generating assets, he has provided analyses concerning market power in support of submissions under

Sections 203 and 205 of the Federal Power Act and analyses required by state regulatory commissions.

- For utilities and power pools preparing structural reforms, he has assisted in examining various facets of proposed reforms. This analysis has included both features of the proposals affecting market efficiency and those that have potential consequences for market power. Where relevant, the analysis also has examined the effects of alternative reforms on the client's financial performance and achievement of other objectives.

- For the New England Power Pool he examined the issue of market power in connection with its movement to market-based pricing for energy, capacity and ancillary services. He also assisted the New England utilities in preparing their market power mitigation proposal. The main results of his analysis were incorporated in NEPOOL's market power filing before FERC.

- As part of a large PHB team he assisted a midwest utility in developing an innovative proposal for electricity industry restructuring. This work formed the basis for that utility's proposals in its state's restructuring proceeding.

- Dr. Hieronymus has contributed substantially to PHB's activities in the restructuring of the California electricity industry. In this context he also is a witness in California and FERC proceedings on the subject of market power and mitigation.

- He has testified in state securitization and stranded cost quantification proceedings, primarily in forecasting the level of market prices that should be used in assessing the future revenues and the operating contribution earned by the owner of the utilities' assets in energy and capacity markets. The market price analyses are tailored to the specific features of the market in which the utility will operate and reflect transmission-constrained trading over a wide geographic area. He also has testified in rebuttal to other parties' testimony concerning stranded costs and assisted companies in internal stranded cost and asset valuation studies.

- He has contributed to the development of benchmarking analyses for U.S. utilities. These have been used in work with PHB's clients to develop regulatory proposals, set cost reduction targets, restructure internal operations and assess merger savings.

- Dr. Hieronymus was a co-developer of a market simulation package that PHB has tailored to region-specific applications. He and other PHB personnel have provided numerous multi-day training sessions using the package to help our utility clients in educating management personnel in the consequences of wholesale and retail deregulation and in developing the skills necessary to succeed in this environment.

**WILLIAM H. HIERONYMUS**
**Senior Vice President**

- Dr. Hieronymus has made numerous presentations to U.S. utility managements on the U.K. electricity system and has arranged meetings with senior executives and regulators in the U.K. for the senior managements of U.S. utilities.
- For a task force of utilities, regulators, legislators and other interested parties created by the Governor's office of a northeastern state he prepared background and briefing papers as part of a PHB assignment to assist in developing a consensus proposal for electricity industry restructuring.
- For an East Coast electricity holding company, he prepared and testified to an analysis of the logic and implementation issues concerning utility-sponsored conservation and demand management programs.
- In connection with nuclear generating plants nearing completion, he has testified in Pennsylvania, Louisiana, Arizona, Illinois, Missouri, New York, Texas, Arkansas, New Mexico and before the Federal Energy Regulatory Commission in plant-in-service rate cases on the issues of equitable and economically efficient treatment of plant cost for tariff setting purposes, regulatory treatment of new plants in other jurisdictions, the prudence of past system planning decisions and assumptions, performance incentives and the life-cycle costs and benefits of the units. In these and other utility regulatory proceedings, Dr. Hieronymus and his colleagues have provided extensive support to counsel, including preparation of interrogatories, cross-examination support and assistance in writing briefs.
- On behalf of utilities in the states of Michigan, Massachusetts, New York, Maine, Indiana, Pennsylvania, New Hampshire and Illinois, he has submitted testimony in regulatory proceedings on the economics of completing nuclear generating plants that are currently under construction. His testimony has covered the likely cost of plant completion, forecasts of operating performance and extensive analyses of ratepayer and shareholder impacts of completion, deferral and cancellation.
- For utilities engaged in nuclear plant construction, Dr. Hieronymus has performed a number of highly confidential assignments to support strategic decisions concerning continuing the construction projects. Areas of inquiry included plant cost, financial feasibility, power marketing opportunities, the impact of potential regulatory treatments of plant cost on shareholders and customers and evaluation of offers to purchase partially completed facilities.
- For an eastern Pennsylvania utility that suffered a nuclear plant shutdown due to NRC sanctions relating to plant management, he filed testimony regarding the extent to which replacement power cost exceeded the costs that would have occurred but for the shutdown.

**WILLIAM H. HIERONYMUS**
**Senior Vice President**

- For a major midwestern utility, he headed a team that assisted senior management in devising its strategic plans including examination of such issues as plant refurbishment/life extension strategies, impacts of increased competition and diversification opportunities.

- On behalf of two West Coast utilities, he testified in a needs certification hearing for a major coal-fired generation complex concerning the economics of the facility relative to competing sources of power, particularly unconventional sources and demand reductions.

- For a large western combination utility, Dr. Hieronymus participated in a major 18-month effort to provide it with an integrated planning and rate case management system. His specific responsibilities included assisting the client in design and integration of electric and gas energy demand forecasts, peak load and load shape forecasts and forecasts of the impacts of conservation and load management programs.

- For two midwestern utilities, he prepared an analysis of intervenor-proposed modifications to the utilities' resource plans. He then testified on their behalf before a legislative committee..

- For a major combination electric and gas utility, he directed the adaptation of a PHB-developed financial simulation model for use in resource planning and evaluation of conservation programs.

**U.K. Assignments**

- Following promulgation of the White Paper setting out the general framework for privatization of the electricity industry in the United Kingdom, Dr. Hieronymus participated extensively in the task forces charged with developing the new market system and regulatory regime. His work on behalf of the Electricity Council and the twelve regional electricity councils focused on the proposed regulatory regime, including the price cap and regulatory formulas, and distribution and transmission use of system tariffs. He was an active participant in industry-government task forces charged with creating the legislation, regulatory framework, initial contracts and rules of the pooling and settlements system. He also assisted the regional companies in the valuation of initial contract offers from the generators, including supporting their successful refusal to contract for the proposed nuclear power plants that subsequently were canceled as being non-commercial.

- During the preparation for privatization, he assisted several of the U.K. individual electricity companies in understanding the evolving system, in development of use of system tariffs, and in developing strategic plans and management and technical capabilities in power purchasing and contracting. He continued to advise a number of clients, including regional companies, power developers, large industrial customers and financial institutions on the U.K. power system for a number of years after privatization.

- Dr. Hieronymus assisted four of the regional electricity companies in negotiating equity ownership positions and developing the power purchase contracts for an 1,825 megawatt combined cycle gas station. He also assisted clients in evaluating other potential generating investments including cogeneration and non-conventional resources.

- He also has consulted on the separate reorganization and privatization of the Scottish electricity sector. PHB's role in that privatization included advising the larger of the two Scottish companies and, through it, the Secretary of State on all phases of the restructuring and privatization, including the drafting of regulations, asset valuation and company strategy.

- He has assisted one of the Regional Electricity Companies in England and Wales in the 1993 through 1995 regulatory proceedings that reset the price caps for its retailing and distribution businesses. Included in this assignment have been policy issues such as incentives for economic purchasing of power, the scope of the price control, and the use of comparisons among companies as a basis for price regulation. His model for determining network refurbishment needs was used by the regulator in determining revenue allowances for capital investments.

- He assisted this same utility in its defense against a hostile takeover, including preparation of its submission to the Cabinet Minister who had the responsibility for determining whether the merger should be referred to the competition authority.

**Assignments Outside the U.S. and U.K.**

- Dr. Hieronymus has assisted a large state-owned European electricity company in evaluating the impacts of the 1997 EU directive on electricity that *inter alia* requires retail access and competitive markets for generation. The assignment includes advice on the organizational solution to elements of the directive requiring a separate transmission system operator and the business need to create a competitive marketing function.

- For the European Bank for Reconstruction and Development he performed analyses of least cost power options, evaluation of the return on a major plant investment that the Bank was considering and forecasts of electricity prices in support of assessment of a major investment in an electricity intensive industrial plant.

- For the OECD he performed a study of energy subsidies worldwide and the impact of subsidy elimination on the environment, particularly on greenhouse gases.

- For the Magyar Villamos Muvek Troszt, the electricity company of Hungary, he developed a contract framework to link the operations of the different entities of an electricity sector in the process of moving from a centralized command and control system to a decentralized, corporatized system.

- For Iberdrola, the largest investor-owned Spanish electricity company, he assisted in development of their proposal for a fundamental reorganization of the electricity sector, its means of compensating generation and distribution companies, its regulation and the phasing out of subsidies. He also has assisted the company in evaluating generation expansion options and in valuing offers for imported power.

- Dr. Hieronymus contributed extensively to a project for the Ukrainian Electricity Ministry, the goal of which is to reorganize the Ukrainian electricity sector and prepare it for transfer to the private sector and the attraction of foreign capital. The proposed reorganization will be based on regional electricity companies, linked by a unified central market, with market-based prices for electricity.

- At the request of the Ministry of Power of the USSR, Dr. Hieronymus participated in the creation of a seminar on electricity restructuring and privatization. The seminar was given for 200 invited Ministerial staff and senior managers for the USSR power system. His specific role was to introduce the requirements and methods of privatization. Subsequent to the breakup of the Soviet Union, he continued to advise the Russian energy and power ministry and government-owned generation and transmission company on restructuring and market development issues.

- On behalf of a large continental electricity company he analyzed the proposed directives from the European Commission on gas and electricity transit (open access regimes) and on the internal market for electricity. The purpose of this assignment was to forecast likely developments in the structure and regulation of the electricity sector in the common market and assist the client in understanding their implications.

- For the electric utility company of the Republic of Ireland, he assessed the likely economic benefit of building an interconnector between Eire and Wales for the sharing of reserves and the interchange of power.

- For a task force representing the Treasury, electric generating and electricity distribution industries in New Zealand, he undertook an analysis of industry structure and regulatory alternatives for achieving economically efficient generation of electricity. The analysis explored how the industry likely would operate under alternative regimes and their implications for asset valuation, electricity pricing, competition and regulatory requirements.

**TARIFF DESIGN METHODOLOGIES AND POLICY ISSUES**

- Dr. Hieronymus participated in a series of studies for the National Grid Company of the United Kingdom and for ScottishPower on appropriate pricing methodologies for transmission, including incentives for efficient investment and location decisions.

- For a U.S. utility client, he directed an analysis of time-differentiated costs based on accounting concepts. The study required selection of rating periods and allocation of costs to time periods and within time periods to rate classes.

- For EPRI, he directed a study that examined the effects of time-of-day rates on the level and pattern of residential electricity consumption.

- For the EPRI-NARUC Rate Design Study, Dr. Hieronymus developed a methodology for designing optimum cost-tracking block rate structures.

- On behalf of a group of cogenerators, he filed testimony before the Energy Select Committee of the UK Parliament on the effects of prices on cogeneration development.

- For the Edison Electric Institute (EEI), he prepared a statement of the industry's position on proposed federal guidelines on fuel adjustment clauses. He also assisted EEI in responding to the U.S. Department of Energy (DOE) guideline on cost-of-service standards.

- For private utility clients, he assisted in the preparation of comments on draft Federal Energy Regulatory Commission (FERC) regulations and in preparing their compliance plans for PURPA Section I33.

- For the EEI Utility Regulatory Analysis Program, he co-authored an analysis of the DOE position on the purposes of the Public Utilities Regulatory Policies Act of 1978. The report focused on the relationship between those purposes and cost-of-service and ratemaking positions under consideration in the generic hearings required by PURPA.

- For a state utilities commission, Dr. Hieronymus assessed its utilities' existing automatic adjustment clauses to determine their compliance with PURPA and recommended modifications.

- For the DOE, he developed an analysis of automatic adjustment clauses currently employed by electric utilities. The focus of this analysis was on efficiency incentive effects.

- For the commissioners of a public utility commission, he assisted in preparation of briefing papers, lines of questioning and proposed findings of fact in a generic rate design proceeding.

## SALES FORECASTING METHODOLOGIES FOR GAS AND ELECTRIC UTILITIES

- For the White House Sub-Cabinet Task Force on the future of the electric utility industry, Dr. Hieronymus co-directed a major analysis of "least-cost planning studies" and "low-growth energy futures." That analysis was the sole demand-side study commissioned by the task force and formed an important basis for the task force's conclusions concerning the need for new facilities and the relative roles of new construction and customer side-of-the-meter programs in utility planning.

- For a large eastern utility, he developed a load forecasting model designed to interface with the utility's revenue forecasting system- planning functions. The model forecasts detailed monthly sales and seasonal peaks for a 10-year period.

- For the DOE, he directed the development of an independent needs assessment model for use by state public utility commissions. This major study developed the capabilities required for independent forecasting by state commissions and constructed a forecasting model for their interim use.

- For several state regulatory commissions, Dr. Hieronymus has consulted in the development of service area level forecasting models of electric utility companies.

- For EPRI, he authored a study of electricity demand and load forecasting models. The study surveyed state-of-the-art models of electricity demand and subjected the most promising models to empirical testing to determine their potential for use in long-term forecasting.

- For a midwestern electric utility, he has provided consulting assistance in improving its load forecast and has testified in defense of the revised forecasting models.

- For an East Coast gas utility, he testified with respect to sales forecasts and provided consulting assistance in improving the models used to forecast residential and commercial sales.

**WILLIAM H. HIERONYMUS**
**Senior Vice President**

**OTHER STUDIES PERTAINING TO REGULATED AND ENERGY COMPANIES**

- In a number of antitrust and regulatory matters, Dr. Hieronymus has performed analyses and litigation support tasks. These include both Sherman Act Section One and Two cases, contract negotiations, generic rate hearings, ITC hearings and a major asset valuation suit. In a major antitrust case, he testified with respect to the demand for business telecommunications services and the impact of various practices on demand and on the market share of a new entrant. For a major electrical equipment vendor he has testified on damages with respect to alleged defects and associated fraud and warranty claims. In connection with mergers for which he is the market power expert, he is assisting clients in responding to the Antitrust Division of the U.S. Department of Justice's Hart-Scott-Rodino requests.

- For a private client, he headed a project that examined the feasibility and value of a major synthetic natural gas project. The study analyzed both the future supply costs of alternative natural gas sources and the effects of potential changes in FPC rate regulations on project viability. The analysis was used in preparing contract negotiation strategies.

- For a industrial client considering development and marketing of a total energy system for cogeneration of electricity and low-grade heat, he developed an estimate of the potential market for the system by geographic area.

- For the U.S. Environmental Protection Agency (EPA), Dr. Hieronymus was the principal investigator in a series of studies for forecasting future supply availability and production costs for various grades of steam and metallurgical coal to be consumed in process heat and utility uses.

Dr. Hieronymus has addressed a number of conferences on such issues as market power, industry restructuring, utility pricing in competitive markets, international developments in utility structure and regulation, risk analysis for regulated investments, price squeezes, rate design, forecasting customer response to innovative rates, intervenor strategies in utility regulatory proceedings, utility deregulation and utility-related opportunities for investment bankers.

Before joining PHB, Dr. Hieronymus was program manager for Energy Market Analysis at Charles River Associates. Previously, he served as a project director at Systems Technology Corporation and as an economist while serving in the U.S. Army. He is a present or past member of the American Economics Association and the International Association of Energy Economists, and a past member of the Task Force on Coal Supply of the New England Energy Policy Commission. He is the author of a number of reports in the field of energy economics and has been an invited speaker at numerous conferences.

**WILLIAM H. HIERONYMUS**
**Senior Vice President**

Dr. Hieronymus received a B.A. from the University of Iowa and M.A. and Ph.D. degrees in economics from the University of Michigan.

Competitive Analysis Screening Model (CASm v7.3)

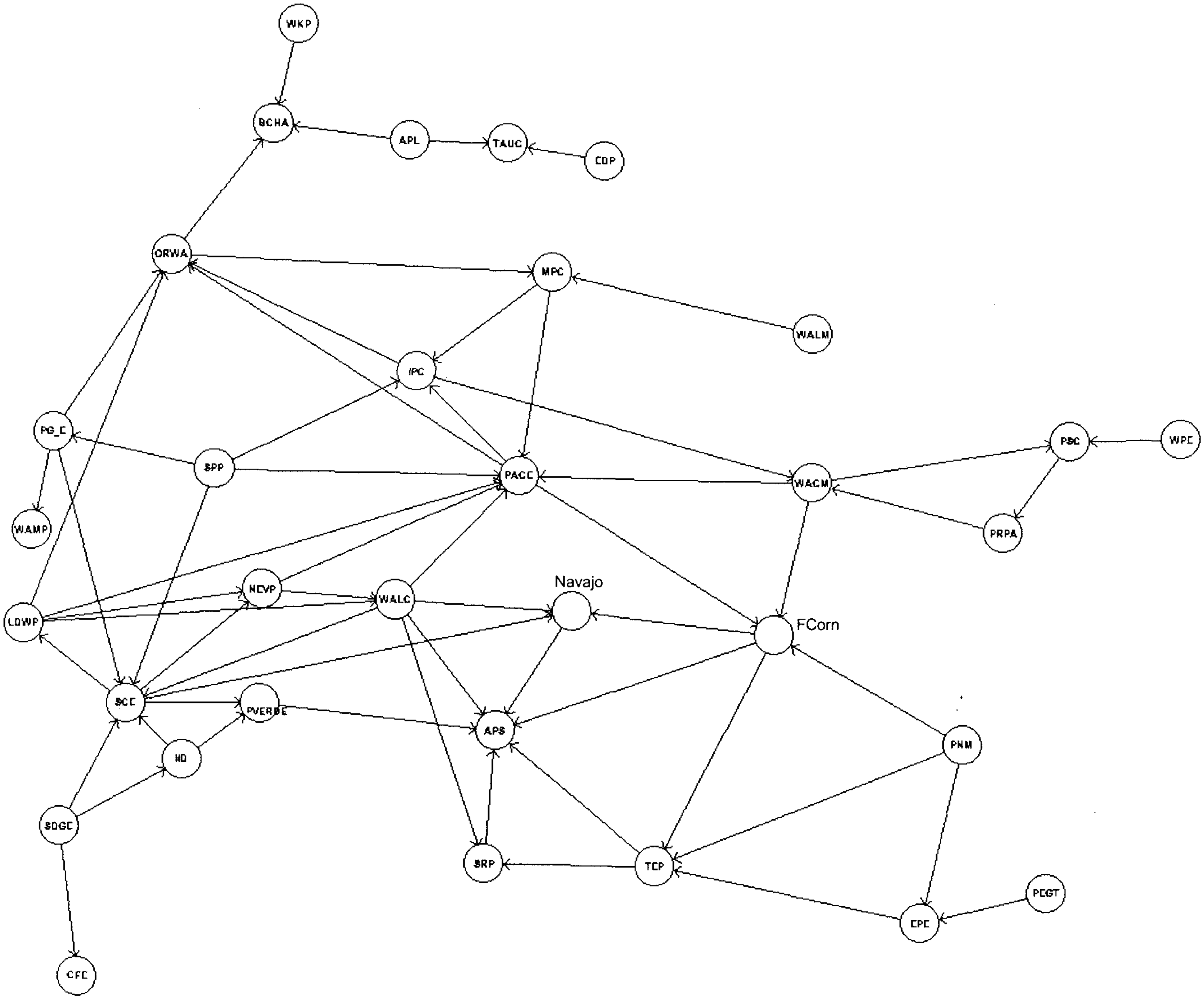
## HHI Report

## APS Market Power Analysis (Base Case)

| Market | Season | Period | BASE APS Mkt Share | HHI |
|---|---|---|---|---|
| APS | Summer | Super-Peak | 22.40% | 1184 |
| APS | Summer | Peak | 21.90% | 1170 |
| APS | Summer | Off-Peak | 22.00% | 1195 |
| APS | Winter | Super-Peak | 24.10% | 1219 |
| APS | Winter | Peak | 22.40% | 1178 |
| APS | Winter | Off-Peak | 22.30% | 1211 |
| APS | Shoulder | Super-Peak | 21.60% | 1148 |
| APS | Shoulder | Peak | 24.00% | 1332 |
| APS | Shoulder | Off-Peak | 9.90% | 1347 |

Attachment WHH-2

# Modeled Nodes In Market Power Analysis



## Generating Capacity Additions in 2001 Case

| Plant | Capacity | Node | Owner | Owner_Share |
|---|---|---|---|---|
| West Phoenix CC4 | 130 | APS | APS | 100% |
| West Phoenix CC5 | 500 | APS | APS<br>Houston Ind | 50%<br>50% |
| Desert Basin | 500 | APS | Houston Ind | 100% |
| Kingman | 480 | WALC | Houston Ind | 100% |
| South Point | 500 | WALC | Calpine | 100% |
| Person GT2 | 140 | PNM | PNM | 100% |

Competitive Analysis Screening Model (CASm v7.3)

## HHI Report

## APS Market Power Analysis (Base Case)

| Market | Season | Period | BASE APS Mkt Share | HHI |
|---|---|---|---|---|
| APS | Summer | Super-Peak | 22.30% | 1188 |
| APS | Summer | Peak | 21.90% | 1197 |
| APS | Summer | Off-Peak | 22.00% | 1277 |
| APS | Winter | Super-Peak | 24.10% | 1225 |
| APS | Winter | Peak | 22.40% | 1194 |
| APS | Winter | Off-Peak | 22.00% | 1358 |
| APS | Shoulder | Super-Peak | 21.60% | 1146 |
| APS | Shoulder | Peak | 24.30% | 1412 |
| APS | Shoulder | Off-Peak | 10.00% | 1896 |

Competitive Analysis Screening Model (CASm v7.3)

## HHI Report.

## APS Market Power Analysis (Including expected 2001 constructions)

| Market | Season | Period | BASE APS Mkt Share | HHI |
|---|---|---|---|---|
| APS | Summer | Super-Peak | 23.00% | 1145 |
| APS | Summer | Peak | 22.70% | 1144 |
| APS | Summer | Off-Peak | 22.00% | 1276 |
| APS | Winter | Super-Peak | 24.70% | 1186 |
| APS | Winter | Peak | 23.00% | 1140 |
| APS | Winter | Off-Peak | 21.90% | 1355 |
| APS | Shoulder | Super-Peak | 22.30% | 1104 |
| APS | Shoulder | Peak | 24.90% | 1328 |
| APS | Shoulder | Off-Peak | 10.00% | 1901 |

Competitive Analysis Screening Model (CASm v7.3)

# Supplier Report

# APS Market Power Analysis (Base Case)

| | |
|---|---|
| Destination Market | APS |
| Period | Summer Super Peak |
| Destination Market Price | 55 |
| HHI | 1188 |

| Supplier | BASE Available (MW) | Supplied (MW) | Market Share (%) |
|---|---|---|---|
| AEPC | 451 | 313 | 2 |
| AES_CA_S | 3199 | 244 | 1.5 |
| ANHM | 808 | 61 | 0.4 |
| APS | 4390 | 3565 | 22.3 |
| BEPC | 579 | 5 | 0 |
| BHPL | 351 | 3 | 0 |
| CGC_CA_N | 1009 | 0 | 0 |
| CSU | 501 | 4 | 0 |
| DGT | 252 | 2 | 0 |
| DUK_CA_N | 2052 | 0 | 0 |
| EPE | 1318 | 665 | 4.2 |
| HOU_CA_S | 3010 | 229 | 1.4 |
| ICPA | 340 | 11 | 0.1 |
| IID | 475 | 47 | 0.3 |
| IPC | 2374 | 38 | 0.2 |
| LDWP | 5640 | 1632 | 10.2 |
| MPC | 72 | 2 | 0 |
| NCPA | 533 | 0 | 0 |
| NEVP | 2145 | 1415 | 8.9 |
| NRG_CA_S | 1583 | 121 | 0.8 |
| PACE | 5140 | 510 | 3.2 |
| PASA | 257 | 27 | 0.2 |
| PEGT | 229 | 19 | 0.1 |
| PG_E | 11088 | 208 | 1.3 |
| PNM | 1533 | 770 | 4.8 |
| PPL_MT | 2089 | 0 | 0 |
| PRPA | 370 | 3 | 0 |
| PV_PVER_MO | 42 | 41 | 0.3 |
| SCE | 7839 | 1494 | 9.4 |
| SDGE | 617 | 47 | 0.3 |
| SEI_CA_N | 2400 | 0 | 0 |
| SPP | 638 | 4 | 0 |
| SRP | 3495 | 2780 | 17.4 |
| TCK_CA_S | 239 | 18 | 0.1 |
| TEP | 1481 | 661 | 4.1 |
| TSGT | 1043 | 8 | 0.1 |
| UPD_CA_S | 579 | 0 | 0 |
| WACM | 2428 | 54 | 0.3 |
| WALC | 1218 | 969 | 6.1 |
| | 74094 | 15971 | 100 |

Competitive Analysis Screening Model (CASm v7.3)

## Supplier Report

## APS Market Power Analysis (Base Case)

| | |
|---|---|
| Destination Market | APS |
| Period | Summer On-Peak |
| Destination Market Price | 35 |
| HHI | 1197 |

| Supplier | BASE Available (MW) | Supplied (MW) | Market Share (%) |
|---|---|---|---|
| AEPC | 382 | 253 | 1.6 |
| ANHM | 767 | 81 | 0.5 |
| APS | 4040 | 3366 | 21.9 |
| BEPC | 577 | 9 | 0.1 |
| BHPL | 284 | 5 | 0 |
| CGC_CA_N | 1005 | 0 | 0 |
| CSU | 425 | 7 | 0 |
| DGT | 246 | 4 | 0 |
| DUK_CA_N | 1778 | 0 | 0 |
| EPE | 1133 | 686 | 4.5 |
| HOU_CA_S | 1793 | 190 | 1.2 |
| ICPA | 339 | 15 | 0.1 |
| IID | 467 | 59 | 0.4 |
| IPC | 1909 | 56 | 0.4 |
| LDWP | 3131 | 1820 | 11.9 |
| MPC | 11 | 0 | 0 |
| NCPA | 403 | 0 | 0 |
| NEVP | 1962 | 1189 | 7.7 |
| NRG_CA_S | 799 | 85 | 0.6 |
| PACE | 5086 | 947 | 6.2 |
| PASA | 83 | 16 | 0.1 |
| PEGT | 228 | 24 | 0.2 |
| PG_E | 7583 | 288 | 1.9 |
| PNM | 1382 | 988 | 6.4 |
| PPL_MT | 1933 | 0 | 0 |
| PRPA | 369 | 6 | 0 |
| PV_PVER_MO | 42 | 40 | 0.3 |
| SCE | 7298 | 1792 | 11.7 |
| SDGE | 614 | 65 | 0.4 |
| SPP | 580 | 6 | 0 |
| SRP | 3255 | 2438 | 15.9 |
| TEP | 1288 | 622 | 4.1 |
| TSGT | 954 | 15 | 0.1 |
| WACM | 1244 | 75 | 0.5 |
| WALC | 307 | 203 | 1.3 |
| | 55891 | 15350 | 100 |

Competitive Analysis Screening Model (CASm v7.3)

**Supplier Report**

**APS Market Power Analysis (Base Case)**

| | |
|---|---|
| Destination Market | APS |
| Period | Summer Off-Peak |
| Destination Market Price | 25 |
| HHI | 1277 |

| Supplier | BASE Available (MW) | Supplied (MW) | Market Share (%) |
|---|---|---|---|
| AEPC | 315 | 125 | 0.9 |
| ANHM | 710 | 131 | 0.9 |
| APS | 3376 | 3071 | 22 |
| BEPC | 567 | 11 | 0.1 |
| BHPL | 256 | 5 | 0 |
| CGC_CA_N | 977 | 0 | 0 |
| CSU | 411 | 8 | 0.1 |
| DGT | 239 | 4 | 0 |
| EPE | 586 | 556 | 4 |
| ICPA | 330 | 15 | 0.1 |
| IID | 301 | 64 | 0.5 |
| IPC | 1335 | 57 | 0.4 |
| LDWP | 2252 | 1234 | 8.8 |
| MPC | 11 | 0 | 0 |
| NCPA | 302 | 0 | 0 |
| NEVP | 1556 | 696 | 5 |
| PACE | 4699 | 782 | 5.6 |
| PASA | 81 | 21 | 0.2 |
| PEGT | 222 | 48 | 0.3 |
| PG_E | 5257 | 490 | 3.5 |
| PNM | 1169 | 1133 | 8.1 |
| PPL_MT | 1710 | 0 | 0 |
| PRPA | 363 | 7 | 0 |
| PV_PVER_MO | 41 | 40 | 0.3 |
| SCE | 6060 | 2336 | 16.7 |
| SDGE | 517 | 95 | 0.7 |
| SPP | 222 | 6 | 0 |
| SRP | 2547 | 2272 | 16.2 |
| TEP | 1045 | 622 | 4.5 |
| TSGT | 927 | 17 | 0.1 |
| WACM | 634 | 69 | 0.5 |
| WALC | 164 | 65 | 0.5 |
| | 39272 | 13981 | 100 |

Competitive Analysis Screening Model (CASm v7.3)

## Supplier Report
## APS Market Power Analysis (Base Case)

| | |
|---|---|
| Destination Market | APS |
| Period | Winter Super Peak |
| Destination Market Price | 55 |
| HHI | 1225 |

| Supplier | BASE Available (MW) | Supplied (MW) | Market Share (%) |
|---|---|---|---|
| AEPC | 451 | 296 | 1.8 |
| AES_CA_S | 3199 | 232 | 1.4 |
| ANHM | 812 | 59 | 0.4 |
| APS | 4596 | 3908 | 24.1 |
| BEPC | 578 | 7 | 0 |
| BHPL | 378 | 5 | 0 |
| CGC_CA_N | 1009 | 0 | 0 |
| CSU | 495 | 6 | 0 |
| DGT | 253 | 3 | 0 |
| DUK_CA_N | 2051 | 0 | 0 |
| EPE | 1336 | 692 | 4.3 |
| HOU_CA_S | 3039 | 221 | 1.4 |
| ICPA | 345 | 14 | 0.1 |
| IID | 426 | 41 | 0.3 |
| IPC | 2498 | 52 | 0.3 |
| LDWP | 5652 | 1594 | 9.8 |
| MPC | 72 | 3 | 0 |
| NCPA | 533 | 0 | 0 |
| NEVP | 2184 | 1333 | 8.2 |
| NRG_CA_S | 1618 | 118 | 0.7 |
| PACE | 5165 | 609 | 3.8 |
| PASA | 258 | 26 | 0.2 |
| PEGT | 229 | 18 | 0.1 |
| PG_E | 11066 | 198 | 1.2 |
| PNM | 1537 | 963 | 5.9 |
| PPL_MT | 2096 | 0 | 0 |
| PRPA | 370 | 5 | 0 |
| PV_PVER_MO | 42 | 41 | 0.3 |
| SCE | 7839 | 1421 | 8.8 |
| SDGE | 617 | 45 | 0.3 |
| SEI_CA_N | 2399 | 0 | 0 |
| SPP | 670 | 6 | 0 |
| SRP | 3561 | 2735 | 16.9 |
| TCK_CA_S | 239 | 17 | 0.1 |
| TEP | 1481 | 660 | 4.1 |
| TSGT | 1059 | 13 | 0.1 |
| UPD_CA_S | 579 | 0 | 0 |
| WACM | 2354 | 85 | 0.5 |
| WALC | 1205 | 789 | 4.9 |
| | 74569 | 16214 | 100 |

Competitive Analysis Screening Model (CASm v7.3)

**Supplier Report**

**APS Market Power Analysis (Base Case)**

| | |
|---|---|
| Destination Market | APS |
| Period | Winter On-Peak |
| Destination Market Price | 35 |
| HHI | 1194 |

| Supplier | BASE Available (MW) | Supplied (MW) | Market Share (%) |
|---|---|---|---|
| AEPC | 382 | 293 | 1.9 |
| ANHM | 770 | 86 | 0.6 |
| APS | 4121 | 3451 | 22.4 |
| BEPC | 577 | 9 | 0.1 |
| BHPL | 284 | 5 | 0 |
| CGC_CA_N | 1005 | 0 | 0 |
| CSU | 413 | 7 | 0 |
| DGT | 248 | 4 | 0 |
| DUK_CA_N | 1777 | 0 | 0 |
| EPE | 1143 | 689 | 4.5 |
| HOU_CA_S | 1793 | 202 | 1.3 |
| ICPA | 343 | 16 | 0.1 |
| IID | 425 | 57 | 0.4 |
| IPC | 2275 | 60 | 0.4 |
| LDWP | 3069 | 1566 | 10.1 |
| MPC | 11 | 1 | 0 |
| NCPA | 354 | 0 | 0 |
| NEVP | 2001 | 1401 | 9.1 |
| NRG_CA_S | 799 | 90 | 0.6 |
| PACE | 5130 | 1140 | 7.4 |
| PASA | 82 | 16 | 0.1 |
| PEGT | 228 | 23 | 0.2 |
| PG_E | 7029 | 307 | 2 |
| PNM | 1385 | 994 | 6.4 |
| PPL_MT | 2024 | 0 | 0 |
| PRPA | 369 | 6 | 0 |
| PV_PVER_MO | 42 | 41 | 0.3 |
| SCE | 6915 | 1615 | 10.5 |
| SDGE | 613 | 69 | 0.4 |
| SPP | 611 | 6 | 0 |
| SRP | 3274 | 2465 | 16 |
| TEP | 1288 | 622 | 4 |
| TSGT | 953 | 16 | 0.1 |
| WACM | 1045 | 72 | 0.5 |
| WALC | 130 | 100 | 0.6 |
| | 55031 | 15428 | 100 |

Competitive Analysis Screening Model (CASm v7.3)

## Supplier Report
## APS Market Power Analysis (Base Case)

| | |
|---|---|
| Destination Market | APS |
| Period | Winter Off-Peak |
| Destination Market Price | 15 |
| HHI | 1358 |

| Supplier | BASE Available (MW) | Supplied (MW) | Market Share (%) |
|---|---|---|---|
| ANHM | 423 | 98 | 0.8 |
| APS | 3243 | 2617 | 22 |
| BHPL | 25 | 1 | 0 |
| CGC_CA_N | 987 | 0 | 0 |
| CSU | 183 | 2 | 0 |
| DGT | 240 | 3 | 0 |
| EPE | 595 | 580 | 4.9 |
| IID | 12 | 12 | 0.1 |
| IPC | 438 | 124 | 1 |
| LDWP | 1447 | 1034 | 8.7 |
| MPC | 11 | 3 | 0 |
| NCPA | 293 | 0 | 0 |
| NEVP | 958 | 614 | 5.1 |
| PACE | 512 | 151 | 1.3 |
| PASA | 9 | 8 | 0.1 |
| PG_E | 5095 | 624 | 5.2 |
| PNM | 497 | 488 | 4.1 |
| PPL_MT | 122 | 0 | 0 |
| PV_PVER_MO | 42 | 41 | 0.3 |
| SCE | 5175 | 2554 | 21.4 |
| SDGE | 523 | 121 | 1 |
| SPP | 99 | 25 | 0.2 |
| SRP | 1917 | 1600 | 13.4 |
| TEP | 1048 | 905 | 7.6 |
| WACM | 518 | 248 | 2.1 |
| WALC | 109 | 69 | 0.6 |
| | 26336 | 11921 | 100 |

Competitive Analysis Screening Model (CASm v7.3)

**Supplier Report**

**APS Market Power Analysis (Base Case)**

| | |
|---|---|
| Destination Market | APS |
| Period | Shoulder Super Peak |
| Destination Market Price | 55 |
| HHI | 1146 |

| Supplier | BASE Available (MW) | Supplied (MW) | Market Share (%) |
|---|---|---|---|
| AEPC | 418 | 299 | 1.9 |
| AES_CA_S | 2856 | 239 | 1.6 |
| ANHM | 771 | 64 | 0.4 |
| APS | 4025 | 3321 | 21.6 |
| BEPC | 510 | 5 | 0 |
| BHPL | 340 | 3 | 0 |
| CGC_CA_N | 958 | 0 | 0 |
| CSU | 457 | 4 | 0 |
| DGT | 227 | 2 | 0 |
| DUK_CA_N | 1811 | 0 | 0 |
| EPE | 1211 | 617 | 4 |
| HOU_CA_S | 2702 | 226 | 1.5 |
| ICPA | 309 | 11 | 0.1 |
| IID | 441 | 45 | 0.3 |
| IPC | 2277 | 43 | 0.3 |
| LDWP | 5178 | 1659 | 10.8 |
| MPC | 72 | 3 | 0 |
| NCPA | 521 | 0 | 0 |
| NEVP | 2021 | 1378 | 9 |
| NRG_CA_S | 1455 | 122 | 0.8 |
| PACE | 4604 | 552 | 3.6 |
| PASA | 240 | 27 | 0.2 |
| PEGT | 208 | 18 | 0.1 |
| PG_E | 10640 | 228 | 1.5 |
| PNM | 1386 | 759 | 4.9 |
| PPL_MT | 1924 | 0 | 0 |
| PRPA | 331 | 3 | 0 |
| PV_PVER_MO | 36 | 36 | 0.2 |
| SCE | 7336 | 1390 | 9 |
| SDGE | 557 | 46 | 0.3 |
| SEI_CA_N | 2142 | 0 | 0 |
| SPP | 617 | 5 | 0 |
| SRP | 3187 | 2568 | 16.7 |
| TCK_CA_S | 224 | 19 | 0.1 |
| TEP | 1345 | 628 | 4.1 |
| TSGT | 934 | 8 | 0.1 |
| UPD_CA_S | 536 | 0 | 0 |
| WACM | 2395 | 60 | 0.4 |
| WALC | 1216 | 1008 | 6.5 |
| | 68701 | 15393 | 100 |

Competitive Analysis Screening Model (CASm v7.3)

## Supplier Report

## APS Market Power Analysis (Base Case)

| | |
|---|---|
| Destination Market | APS |
| Period | Shoulder On-Peak |
| Destination Market Price | 35 |
| HHI | 1412 |

| Supplier | BASE Available (MW) | Supplied (MW) | Market Share (%) |
|---|---|---|---|
| AEPC | 350 | 126 | 1 |
| ANHM | 730 | 64 | 0.5 |
| APS | 3682 | 3010 | 24.3 |
| BEPC | 508 | 6 | 0.1 |
| BHPL | 274 | 3 | 0 |
| CGC_CA_N | 953 | 0 | 0 |
| CSU | 376 | 5 | 0 |
| DGT | 221 | 3 | 0 |
| DUK_CA_N | 1549 | 0 | 0 |
| EPE | 1030 | 614 | 5 |
| ICPA | 308 | 10 | 0.1 |
| IID | 436 | 47 | 0.4 |
| IPC | 1881 | 43 | 0.3 |
| LDWP | 2849 | 1066 | 8.6 |
| MPC | 11 | 0 | 0 |
| NCPA | 367 | 0 | 0 |
| NEVP | 1841 | 676 | 5.5 |
| PACE | 4550 | 557 | 4.5 |
| PASA | 74 | 13 | 0.1 |
| PEGT | 207 | 23 | 0.2 |
| PG_E | 6968 | 240 | 1.9 |
| PNM | 1243 | 788 | 6.4 |
| PPL_MT | 1789 | 0 | 0 |
| PRPA | 330 | 4 | 0 |
| PV_PVER_MO | 36 | 36 | 0.3 |
| SCE | 6674 | 1912 | 15.4 |
| SDGE | 553 | 49 | 0.4 |
| SPP | 559 | 5 | 0 |
| SRP | 2929 | 2368 | 19.1 |
| TEP | 1156 | 585 | 4.7 |
| TSGT | 846 | 10 | 0.1 |
| WACM | 959 | 47 | 0.4 |
| WALC | 212 | 76 | 0.6 |
| | 50638 | 12387 | 100 |

Competitive Analysis Screening Model (CASm v7.3)

## Supplier Report

## APS Market Power Analysis (Base Case)

| | |
|---|---|
| Destination Market | APS |
| Period | Shoulder Off-Peak |
| Destination Market Price | 10 |
| HHI | 1896 |

| Supplier | BASE Available (MW) | Supplied (MW) | Market Share (%) |
|---|---|---|---|
| ANHM | 403 | 144 | 1.8 |
| APS | 797 | 797 | 10 |
| BHPL | 25 | 3 | 0 |
| CSU | 3 | 0 | 0 |
| DGT | 3 | 0 | 0 |
| EPE | 430 | 430 | 5.4 |
| IID | 24 | 15 | 0.2 |
| IPC | 392 | 269 | 3.4 |
| LDWP | 706 | 706 | 8.9 |
| MPC | 10 | 6 | 0.1 |
| NEVP | 511 | 511 | 6.4 |
| PACE | 134 | 134 | 1.7 |
| PASA | 7 | 7 | 0.1 |
| PG_E | 4644 | 166 | 2.1 |
| PNM | 278 | 278 | 3.5 |
| PPL_MT | 116 | 0 | 0 |
| PV_PVER_MO | 36 | 36 | 0.5 |
| SCE | 4001 | 3108 | 39 |
| SDGE | 450 | 161 | 2 |
| SPP | 75 | 42 | 0.5 |
| SRP | 518 | 518 | 6.5 |
| WACM | 496 | 496 | 6.2 |
| WALC | 132 | 132 | 1.7 |
| | 15456 | 7962 | 100 |

Competitive Analysis Screening Model (CASm v7.3)

## Supplier Report

## APS Market Power Analysis (Including expected 2001 constructions)

| | |
|---|---|
| Destination Market | APS |
| Period | Summer Super Peak |
| Destination Market Price | 55 |
| HHI | 1145 |

| Supplier | BASE Available (MW) | Supplied (MW) | Market Share (%) |
|---|---|---|---|
| AEPC | 452 | 276 | 1.6 |
| AES_CA_S | 3204 | 239 | 1.4 |
| ANHM | 810 | 60 | 0.4 |
| APS | 4741 | 3917 | 23 |
| BEPC | 563 | 6 | 0 |
| BHPL | 342 | 3 | 0 |
| CGC | 1459 | 273 | 1.6 |
| CSU | 488 | 5 | 0 |
| DGT | 245 | 2 | 0 |
| DUK_CA_N | 2057 | 0 | 0 |
| EPE | 1320 | 665 | 3.9 |
| HOU | 4134 | 1177 | 6.9 |
| ICPA | 341 | 10 | 0.1 |
| IID | 475 | 46 | 0.3 |
| IPC | 2380 | 38 | 0.2 |
| LDWP | 5648 | 1493 | 8.8 |
| MPC | 73 | 2 | 0 |
| NCPA | 534 | 0 | 0 |
| NEVP | 2148 | 1258 | 7.4 |
| NRG_CA_S | 1586 | 118 | 0.7 |
| PACE | 5148 | 466 | 2.7 |
| PASA | 257 | 27 | 0.2 |
| PEGT | 230 | 19 | 0.1 |
| PG_E | 11116 | 204 | 1.2 |
| PNM | 1654 | 769 | 4.5 |
| PPL_MT | 2094 | 0 | 0 |
| PRPA | 360 | 4 | 0 |
| PV_PVER_MO | 42 | 41 | 0.2 |
| SCE | 7851 | 1463 | 8.6 |
| SDGE | 618 | 46 | 0.3 |
| SEI_CA_N | 2406 | 0 | 0 |
| SPP | 640 | 4 | 0 |
| SRP | 3498 | 2785 | 16.4 |
| TCK_CA_S | 240 | 18 | 0.1 |
| TEP | 1482 | 661 | 3.9 |
| UPD_CA_S | 580 | 0 | 0 |
| WACM | 2362 | 58 | 0.3 |
| WALC | 1219 | 858 | 5 |
| | 75084 | 17011 | 100 |

Competitive Analysis Screening Model (CASm v7.3)

## Supplier Report

## APS Market Power Analysis (Including expected 2001 constructions)

| | |
|---|---|
| Destination Market | APS |
| Period | Summer On-Peak |
| Destination Market Price | 35 |
| HHI | 1144 |

| Supplier | BASE Available (MW) | Supplied (MW) | Market Share (%) |
|---|---|---|---|
| AEPC | 382 | 223 | 1.4 |
| ANHM | 769 | 79 | 0.5 |
| APS | 4391 | 3716 | 22.7 |
| BEPC | 560 | 11 | 0.1 |
| BHPL | 276 | 6 | 0 |
| CGC | 1454 | 260 | 1.6 |
| CSU | 412 | 8 | 0.1 |
| DGT | 239 | 5 | 0 |
| DUK_CA_N | 1781 | 0 | 0 |
| EPE | 1134 | 687 | 4.2 |
| HOU | 2914 | 1126 | 6.9 |
| ICPA | 340 | 15 | 0.1 |
| IID | 467 | 58 | 0.4 |
| IPC | 1912 | 57 | 0.3 |
| LDWP | 3134 | 1649 | 10.1 |
| MPC | 11 | 0 | 0 |
| NCPA | 404 | 0 | 0 |
| NEVP | 1964 | 1052 | 6.4 |
| NRG_CA_S | 800 | 83 | 0.5 |
| PACE | 5092 | 863 | 5.3 |
| PASA | 83 | 16 | 0.1 |
| PEGT | 229 | 24 | 0.1 |
| PG_E | 7597 | 283 | 1.7 |
| PNM | 1502 | 987 | 6 |
| PPL_MT | 1937 | 0 | 0 |
| PRPA | 359 | 7 | 0 |
| PV_PVER_MO | 42 | 40 | 0.2 |
| SCE | 7306 | 1749 | 10.7 |
| SDGE | 615 | 63 | 0.4 |
| SPP | 581 | 6 | 0 |
| SRP | 3256 | 2438 | 14.9 |
| TEP | 1289 | 622 | 3.8 |
| WACM | 1208 | 81 | 0.5 |
| WALC | 307 | 179 | 1.1 |
| | 56943 | 16395 | 100 |

Competitive Analysis Screening Model (CASm v7.3)

## Supplier Report

## APS Market Power Analysis (Including expected 2001 constructions)

| | |
|---|---|
| Destination Market | APS |
| Period | Summer Off-Peak |
| Destination Market Price | 25 |
| HHI | 1276 |

| Supplier | BASE Available (MW) | Supplied (MW) | Market Share (%) |
|---|---|---|---|
| AEPC | 316 | 125 | 0.9 |
| ANHM | 712 | 131 | 0.9 |
| APS | 3378 | 3071 | 22 |
| BEPC | 545 | 14 | 0.1 |
| BHPL | 246 | 6 | 0 |
| CGC | 980 | 0 | 0 |
| CSU | 395 | 10 | 0.1 |
| DGT | 230 | 6 | 0 |
| EPE | 587 | 556 | 4 |
| ICPA | 331 | 15 | 0.1 |
| IID | 301 | 64 | 0.5 |
| IPC | 1338 | 61 | 0.4 |
| LDWP | 2255 | 1234 | 8.8 |
| MPC | 11 | 0 | 0 |
| NCPA | 303 | 0 | 0 |
| NEVP | 1558 | 697 | 5 |
| PACE | 4707 | 782 | 5.6 |
| PASA | 81 | 21 | 0.2 |
| PEGT | 222 | 48 | 0.3 |
| PG_E | 5271 | 490 | 3.5 |
| PNM | 1170 | 1133 | 8.1 |
| PPL_MT | 1714 | 0 | 0 |
| PRPA | 349 | 9 | 0.1 |
| PV_PVER_MO | 41 | 40 | 0.3 |
| SCE | 6070 | 2336 | 16.7 |
| SDGE | 519 | 95 | 0.7 |
| SPP | 223 | 6 | 0 |
| SRP | 2549 | 2272 | 16.2 |
| TEP | 1046 | 623 | 4.5 |
| WACM | 610 | 75 | 0.5 |
| WALC | 164 | 65 | 0.5 |
| | 38312 | 13985 | 100 |

Competitive Analysis Screening Model (CASm v7.3)

## Supplier Report

## APS Market Power Analysis (Including expected 2001 constructions)

| | |
|---|---|
| Destination Market | APS |
| Period | Winter Super Peak |
| Destination Market Price | 55 |
| HHI | 1186 |

| Supplier | BASE Available (MW) | Supplied (MW) | Market Share (%) |
|---|---|---|---|
| AEPC | 452 | 261 | 1.5 |
| AES_CA_S | 3204 | 228 | 1.3 |
| ANHM | 814 | 58 | 0.3 |
| APS | 4947 | 4257 | 24.7 |
| BEPC | 563 | 8 | 0 |
| BHPL | 368 | 6 | 0 |
| CGC | 1459 | 258 | 1.5 |
| CSU | 482 | 7 | 0 |
| DGT | 246 | 4 | 0 |
| DUK_CA_N | 2056 | 0 | 0 |
| EPE | 1338 | 692 | 4 |
| HOU | 4164 | 1155 | 6.7 |
| ICPA | 345 | 14 | 0.1 |
| IID | 426 | 40 | 0.2 |
| IPC | 2504 | 52 | 0.3 |
| LDWP | 5661 | 1451 | 8.4 |
| MPC | 73 | 3 | 0 |
| NCPA | 534 | 0 | 0 |
| NEVP | 2187 | 1182 | 6.8 |
| NRG_CA_S | 1620 | 115 | 0.7 |
| PACE | 5173 | 564 | 3.3 |
| PASA | 258 | 26 | 0.1 |
| PEGT | 230 | 18 | 0.1 |
| PG_E | 11094 | 195 | 1.1 |
| PNM | 1658 | 962 | 5.6 |
| PPL_MT | 2102 | 0 | 0 |
| PRPA | 360 | 5 | 0 |
| PV_PVER_MO | 42 | 41 | 0.2 |
| SCE | 7850 | 1405 | 8.1 |
| SDGE | 618 | 44 | 0.3 |
| SEI_CA_N | 2405 | 0 | 0 |
| SPP | 671 | 6 | 0 |
| SRP | 3564 | 2736 | 15.9 |
| TCK_CA_S | 239 | 17 | 0.1 |
| TEP | 1482 | 661 | 3.8 |
| UPD_CA_S | 580 | 0 | 0 |
| WACM | 2290 | 92 | 0.5 |
| WALC | 1206 | 696 | 4 |
| | 75542 | 17256 | 100 |

Competitive Analysis Screening Model (CASm v7.3)

## Supplier Report

## APS Market Power Analysis (Including expected 2001 constructions)

| | |
|---|---|
| Destination Market | APS |
| Period | Winter On-Peak |
| Destination Market Price | 35 |
| HHI | 1140 |

| Supplier | BASE Available (MW) | Supplied (MW) | Market Share (%) |
|---|---|---|---|
| AEPC | 382 | 256 | 1.6 |
| ANHM | 771 | 83 | 0.5 |
| APS | 4472 | 3789 | 23 |
| BEPC | 560 | 12 | 0.1 |
| BHPL | 276 | 6 | 0 |
| CGC | 1454 | 300 | 1.8 |
| CSU | 401 | 8 | 0.1 |
| DGT | 240 | 5 | 0 |
| DUK_CA_N | 1780 | 0 | 0 |
| EPE | 1144 | 688 | 4.2 |
| HOU | 2913 | 1173 | 7.1 |
| ICPA | 344 | 15 | 0.1 |
| IID | 425 | 55 | 0.3 |
| IPC | 2278 | 61 | 0.4 |
| LDWP | 3072 | 1414 | 8.6 |
| MPC | 11 | 0 | 0 |
| NCPA | 355 | 0 | 0 |
| NEVP | 2003 | 1230 | 7.5 |
| NRG_CA_S | 800 | 87 | 0.5 |
| PACE | 5135 | 1026 | 6.2 |
| PASA | 83 | 16 | 0.1 |
| PEGT | 228 | 23 | 0.1 |
| PG_E | 7040 | 296 | 1.8 |
| PNM | 1506 | 988 | 6 |
| PPL_MT | 2027 | 0 | 0 |
| PRPA | 359 | 8 | 0 |
| PV_PVER_MO | 42 | 41 | 0.2 |
| SCE | 6922 | 1580 | 9.6 |
| SDGE | 614 | 66 | 0.4 |
| SPP | 612 | 6 | 0 |
| SRP | 3276 | 2454 | 14.9 |
| TEP | 1288 | 622 | 3.8 |
| WACM | 1015 | 76 | 0.5 |
| WALC | 130 | 87 | 0.5 |
| | 56082 | 16473 | 100 |

Competitive Analysis Screening Model (CASm v7.3)

## Supplier Report

## APS Market Power Analysis (Including expected 2001 constructions)

| | |
|---|---|
| Destination Market | APS |
| Period | Winter Off-Peak |
| Destination Market Price | 15 |
| HHI | 1355 |

| Supplier | BASE Available (MW) | Supplied (MW) | Market Share (%) |
|---|---|---|---|
| ANHM | 424 | 98 | 0.8 |
| APS | 3245 | 2617 | 21.9 |
| BHPL | 24 | 1 | 0 |
| CGC | 990 | 0 | 0 |
| CSU | 176 | 1 | 0 |
| DGT | 232 | 3 | 0 |
| EPE | 595 | 580 | 4.9 |
| IID | 12 | 12 | 0.1 |
| IPC | 439 | 129 | 1.1 |
| LDWP | 1449 | 1034 | 8.7 |
| MPC | 11 | 3 | 0 |
| NCPA | 294 | 0 | 0 |
| NEVP | 959 | 614 | 5.1 |
| PACE | 513 | 151 | 1.3 |
| PASA | 9 | 8 | 0.1 |
| PG_E | 5111 | 625 | 5.2 |
| PNM | 497 | 488 | 4.1 |
| PPL_MT | 123 | 0 | 0 |
| PV_PVER_MO | 42 | 41 | 0.3 |
| SCE | 5184 | 2555 | 21.4 |
| SDGE | 524 | 122 | 1 |
| SPP | 100 | 25 | 0.2 |
| SRP | 1919 | 1601 | 13.4 |
| TEP | 1049 | 906 | 7.6 |
| WACM | 500 | 257 | 2.2 |
| WALC | 109 | 69 | 0.6 |
| | 25505 | 11940 | 100 |

Competitive Analysis Screening Model (CASm v7.3)

**Supplier Report**

**APS Market Power Analysis (Including expected 2001 constructions)**

| | |
|---|---|
| Destination Market | APS |
| Period | Shoulder Super Peak |
| Destination Market Price | 55 |
| HHI | 1104 |

| Supplier | BASE Available (MW) | Supplied (MW) | Market Share (%) |
|---|---|---|---|
| AEPC | 419 | 263 | 1.6 |
| AES_CA_S | 2861 | 234 | 1.4 |
| ANHM | 773 | 63 | 0.4 |
| APS | 4370 | 3667 | 22.3 |
| BEPC | 496 | 5 | 0 |
| BHPL | 331 | 4 | 0 |
| CGC | 1400 | 276 | 1.7 |
| CSU | 445 | 5 | 0 |
| DGT | 221 | 2 | 0 |
| DUK_CA_N | 1816 | 0 | 0 |
| EPE | 1213 | 617 | 3.8 |
| HOU | 3806 | 1164 | 7.1 |
| ICPA | 310 | 11 | 0.1 |
| IID | 442 | 45 | 0.3 |
| IPC | 2283 | 42 | 0.3 |
| LDWP | 5186 | 1511 | 9.2 |
| MPC | 73 | 2 | 0 |
| NCPA | 522 | 0 | 0 |
| NEVP | 2024 | 1224 | 7.5 |
| NRG_CA_S | 1457 | 119 | 0.7 |
| PACE | 4612 | 502 | 3.1 |
| PASA | 240 | 26 | 0.2 |
| PEGT | 209 | 18 | 0.1 |
| PG_E | 10667 | 224 | 1.4 |
| PNM | 1505 | 758 | 4.6 |
| PPL_MT | 1929 | 0 | 0 |
| PRPA | 322 | 3 | 0 |
| PV_PVER_MO | 36 | 36 | 0.2 |
| SCE | 7347 | 1366 | 8.3 |
| SDGE | 558 | 45 | 0.3 |
| SEI_CA_N | 2147 | 0 | 0 |
| SPP | 619 | 5 | 0 |
| SRP | 3189 | 2573 | 15.7 |
| TCK_CA_S | 224 | 18 | 0.1 |
| TEP | 1346 | 628 | 3.8 |
| UPD_CA_S | 537 | 0 | 0 |
| WACM | 2330 | 64 | 0.4 |
| WALC | 1217 | 893 | 5.4 |
| | 69762 | 16415 | 100 |

Competitive Analysis Screening Model (CASm v7.3)

***Supplier Report***

## APS Market Power Analysis (Including expected 2001 constructions)

| | |
|---|---|
| Destination Market | APS |
| Period | Shoulder On-Peak |
| Destination Market Price | 35 |
| HHI | 1328 |

| Supplier | BASE Available (MW) | Supplied (MW) | Market Share (%) |
|---|---|---|---|
| AEPC | 350 | 115 | 0.9 |
| ANHM | 731 | 63 | 0.5 |
| APS | 4026 | 3343 | 24.9 |
| BEPC | 493 | 8 | 0.1 |
| BHPL | 266 | 4 | 0 |
| CGC | 1393 | 144 | 1.1 |
| CSU | 365 | 6 | 0 |
| DGT | 214 | 3 | 0 |
| EPE | 1031 | 614 | 4.6 |
| HOU | 2672 | 815 | 6.1 |
| ICPA | 308 | 10 | 0.1 |
| IID | 437 | 46 | 0.3 |
| IPC | 1884 | 44 | 0.3 |
| LDWP | 2851 | 999 | 7.4 |
| MPC | 11 | 0 | 0 |
| NCPA | 367 | 0 | 0 |
| NEVP | 1842 | 618 | 4.6 |
| PACE | 4555 | 520 | 3.9 |
| PASA | 74 | 13 | 0.1 |
| PEGT | 208 | 24 | 0.2 |
| PG_E | 6979 | 237 | 1.8 |
| PNM | 1360 | 788 | 5.9 |
| PPL_MT | 1792 | 0 | 0 |
| PRPA | 320 | 5 | 0 |
| PV_PVER_MO | 36 | 36 | 0.3 |
| SCE | 6680 | 1855 | 13.8 |
| SDGE | 554 | 48 | 0.4 |
| SPP | 560 | 4 | 0 |
| SRP | 2930 | 2348 | 17.5 |
| TEP | 1156 | 585 | 4.4 |
| WACM | 930 | 50 | 0.4 |
| WALC | 212 | 69 | 0.5 |
| | 51759 | 13415 | 100 |

Competitive Analysis Screening Model (CASm v7.3)

## Supplier Report

## APS Market Power Analysis (Including expected 2001 constructions)

| | |
|---|---|
| Destination Market | APS |
| Period | Shoulder Off-Peak |
| Destination Market Price | 10 |
| HHI | 1901 |

| Supplier | BASE Available (MW) | Supplied (MW) | Market Share (%) |
|---|---|---|---|
| ANHM | 404 | 145 | 1.8 |
| APS | 798 | 798 | 10 |
| BHPL | 24 | 3 | 0 |
| CSU | 3 | 0 | 0 |
| DGT | 3 | 0 | 0 |
| EPE | 431 | 431 | 5.4 |
| IID | 24 | 15 | 0.2 |
| IPC | 393 | 270 | 3.4 |
| LDWP | 708 | 708 | 8.9 |
| MPC | 10 | 6 | 0.1 |
| NEVP | 512 | 512 | 6.4 |
| PACE | 135 | 135 | 1.7 |
| PASA | 7 | 7 | 0.1 |
| PG_E | 4654 | 167 | 2.1 |
| PNM | 278 | 278 | 3.5 |
| PPL_MT | 116 | 0 | 0 |
| PV_PVER_MO | 36 | 36 | 0.5 |
| SCE | 4006 | 3114 | 39.1 |
| SDGE | 451 | 162 | 2 |
| SPP | 76 | 42 | 0.5 |
| SRP | 519 | 519 | 6.5 |
| WACM | 482 | 482 | 6.1 |
| WALC | 132 | 132 | 1.7 |
| | 15466 | 7962 | 100 |

## Abbreviations Used

| Node Name | Full Company Name |
|---|---|
| AEPC | Arizona Electric Power Coop. |
| AES_CA_S | AES Corp. |
| ANHM | Anaheim CA, City of |
| APL | Alberta Power Limited |
| APS | Arizona Public Service Company |
| BCHA | British Columbia Hydro & Power Authority |
| BEPC | Basin Electric Power Cooperative |
| BHPL | Black Hills Power & Light |
| BPA | Bonneville Power Authority |
| CCSF | San Francisco, City of |
| CDWR | Department of Water Resources/California |
| CFE | Comision Federal de Electricidad |
| CGC_CA_N | Calpine Geysers Co., L.P. |
| CHPD | Chelan County PUD No. 1 |
| CLPD | Clark Public Utilities |
| CSU | Colorado Springs Utilities |
| DGT | Deseret Generation & Transmission Co-operative |
| DOPD | Douglas County PUD No. 1 |
| DUK_CA_N | Duke |
| DYN_CA_S | Dynegy |
| EDP | Edmonton Power |
| EPE | El Paso Electric Company |
| FPL_CA_N | FPL Group |
| GCPD | Grant County PUD |
| HOU_CA_S | Houston Industries |
| ICPA | Intermountain Consumer Power Association |
| IID | Imperial Irrigation District |
| IPC | Idaho Power Company |
| LDWP | Los Angeles Department of Water and Power (Non_WESCO) |
| MPC | Montana Power Company |
| NCPA | Northern California Power Agency |
| NEVP | Nevada Power Company |
| NRG_CA_S | NRG |
| PACE | PacifiCorp East |
| PACW | Pacificorp West |
| PASA | Pasadena CA, City of |
| PEGT | Plains Electric G&T Coop |
| PG&E | Pacific Gas & Electric Company |
| PGE | Portland General Electric |
| PNM | Public Service of New Mexico |
| PPL_MT | PPL |
| PRPA | Platte River Power Authority |
| PSC | Public Service of Colorado |
| PSE | Puget Sound Power & Light |
| SCE | Southern California Edison Company |
| SCL | Seattle City Light |
| SDGE | San Diego Gas & Electric |
| SEI_CA_N | SEI |

## Abbreviations Used

| | |
|---|---|
| SMUD | Sacramento Municipal Utility District |
| SPP | Sierra Pacific |
| SRP | Salt River Project |
| TAUC | Transalta Utilities Corp. |
| TCK_CA_S | Thermo Ecotek |
| TCL | Tacoma City Light |
| TEP | Tucson Electric Power Company |
| TID | Turlock Irrigation District |
| TSGT | Tri-Sate Generation and Transmission Association |
| UPD_CA_S | San Diego Unified Port District |
| USLC | U.S. Bureau of Reclamation - Lower Colorado |
| WACM | WAPA - CM |
| WALC | WAPA - DSW |
| WALM | WAPA - LM |
| WAMP | WAPA - SN |
| WAOR | Washinton-Oregon Composite |
| WKP | West Kootenay Power Ltd. |
| WPE | WestPlains Energy |
| WWPC | Washington Water Power Company |

**Non-Node Companies Making Purchases or Sales**

| Abbreviation | Company Name |
|---|---|
| ACC | Altamont Cogeneration Corp. |
| AETC | Amoco Energy Trading Corp. |
| AGV | Amedee Geothermal Venture I |
| AHAD | U.S. Army Hawthorne Ammo Depot |
| AMAT | American Atlas No. 1, Ltd. |
| AMOR | Amor II Empire Farms |
| APPA | Arizona Power Pooling Assoc. |
| ARCO | ARCO Oil & Gas |
| AZSA | Azusa Light & Water Dept. |
| BCH | Birch Creek Hydro |
| BCL | Badger Creek, Ltd. |
| BCOG | Brush Cogeneration Partners |
| BCWW | Big Creek Water Works, Ltd. |
| BEP | BIO-Energy Partners |
| BFP | Burney Forest Products |
| BGEO | Beowawe Geothermal |
| BGI | Billings Generation, Inc. |
| BHC | Big Horn County Electric Coop, Inc. |
| BIO | Biomass One, L.P. |
| BLED | Blanding Electric Dept. |
| BML | Bear Mountain, Ltd. |
| BMP | Burney Mountain Power |
| BNNG | Banning Electric Dept. |
| BOUL | Boulder 75th Street |
| BOYD | Boyd, James |
| BPAC | Bonneville Pacific Corp. |

## Abbreviations Used

| | |
|---|---|
| BPC | Berry Petroleum Co. |
| BPP | Brady Power Partners |
| BREM | Bremerton, Port of |
| BRIG | Brigham City Light & Power |
| BROW | Brownsville, Port of |
| BURL | Burlington Municipal Light & Power |
| BVLC | Big Valley Lumber Co. |
| CALR | CalResources, L.L.C. |
| CANB | Canby Electric Board |
| CARD | Cardinal Cogen |
| CBET | Boulder/Betasso, City of |
| CBRT | Boulder City of/Roberts Tunnel |
| CCA | Container Corp. of America |
| CCCL | Chalk Cliff Cogen, Ltd. |
| CCOG | Coalinga Cogeneration Co. |
| CCWD | Calaveras County Water District |
| CDMH | CDM Hydro |
| CDN | California Dept of Navy |
| CECO | Cook Electric Co. |
| CEMC | Commercial Energy Management Co. |
| CEN | Colstrip Energy, L.P. |
| CGP | Calistoga Geothermal Partners |
| CHEV | Chevron USA, Inc. |
| CLFC | Cheyenne Light, Fuel & Power Co. |
| CMT | Central Montana Electric Power Coop |
| CMU | Center Municipal Utility System |
| CODM | Des Moines, City of |
| COID | Central Oregon Irrigation District |
| COLL | Collins Pine Co. |
| COLT | Colton Electric Utility Dept. |
| COO | Ouray, City of |
| COOH | Oak Harbor, City of |
| COPP | Colorado Power Partners |
| COSF | San Francisco, City & County of |
| COSS | Strontia Springs, City of |
| COV | Vallelito, City of |
| COWW | Walla Walla, City of |
| COXE | Cogentrix Energy, Inc. |
| CROC | Crockett Cogen |
| DCC | Dow Chemical Co. |
| DCL | Double C, Ltd. |
| DDP | Dillon Dam Project |
| DEX | Dexzel, Inc. |
| DMS | Denver Metro Sewage |
| DPPP | Desert Peak Power Plant |
| DRJL | D.R. Johnson Lumber Co. |
| DWGI | Diamond Walnut Growers, Inc. |
| DYN | Dynamis, Inc. |
| EGP | Energy Growth Partnership I |

**Abbreviations Used**

| | |
|---|---|
| ELDH | El Dorado Hydro (Montgomery Creek) |
| ENSI | Energy Services, Inc. |
| EWEB | Eugene Water & Electric Board |
| EWEB | Eugene Water & Electric Board |
| FAIR | Fairhaven Power Co. |
| FALE | Fale-Safe, Inc. |
| FCHP | Falls Creek HP, L.P. |
| FID | Farmers Irrigation District |
| FLOW | Flowind Corp. |
| FMES | Fallon Municipal Electric System |
| FNA | Fiberweb North America |
| FNA | Fiberweb North America |
| FOOT | Foothills Water Treatment |
| FPA | Friant Power Authority |
| FRITO | Frito Lay, Inc. |
| GALL | Gallup Electric Utility |
| GATX | GATX-Calpine Cogen.-Agnews, Inc. |
| GCC | Gaylord Container Corp. |
| GDH | Galesville Dam Hydro |
| GEP | Geothermal Energy Partners, L.P. |
| GILL | Gillette Municipal Power Dept. |
| GLPC | Garland Light & Power Co. |
| GPC | Georgia Pacific Corp. |
| GREEL | Greeley Gas Co. Division of Atmos Energy |
| GUOA | Greenleaf Unit One Associates, Inc. |
| GUTA | Greenleaf Unit Two Associates, Inc. |
| GVR | Grand Valley Rural Power Line, Inc. |
| GWF | GWF Power Systems, L.P. |
| HADS | Hadson Corp. |
| HANF | Hanford, L.P. |
| HAYH | Haypress Hydroelectric, Inc. |
| HCE | Holy Cross Electric Assoc., Inc. |
| HCLP | Helper City Light & Power Dept. |
| HCUS | Hershey Chocolate USA |
| HERM | Hermiston Generating Co., L.P. |
| HLPC | Honey Lake Power Co. |
| HMWD | Humboldt Bay Municipal Water District |
| HSL | High Sierra, Ltd. |
| HWI | Howden Windparks, Inc. |
| HYDY | Hydrodynamics, Inc. |
| IMTR | Intermountain Rural Electric Association |
| IPA | Intermountain Power Agency |
| ISCI | IPT SRI Cogeneration, Inc. |
| ITRI | International Turbine Research, Inc. |
| IVHP | Indian Valley Hydroelectric Partners |
| JMK | J.M. Keating (Rock Creek) |
| JULE | Julesburg Municipal Power & Light |
| JVEP | Jackson Valley Energy Partners, L.P. |
| KESK | KES Kingsburg, L.P. |

## Abbreviations Used

| | |
|---|---|
| KFL | Kern Front, Ltd. |
| KING | Kingston, Port of |
| KWI | Kenetech Windpower, Inc. |
| LGP | Landfill General Partnership I |
| LGRS | Laidlaw Gas Recovery Systems, Inc. |
| LID | Lacomb Irrigation District |
| LMUD | Lassen Municipal Utility District |
| LOL | Live Oak, Ltd. |
| MBPL | Mendota Biomass Power, Ltd. |
| MCC | Midset Cogeneration Co. |
| MCH | Mink Creek Hydro |
| MCKL | McKittrick, Ltd. |
| MCLP | Martinez Cogen, L.P. |
| MCPA | Madera-Chowchilla Power Authority |
| MDNR | Montana Dept. of Natural Resources |
| MEGA | MEGA Renewables |
| MELP | Modesto Energy, L.P. |
| MERC | Merced Irrigation District |
| MHLP | Malacha Hydro, L.P. |
| MID | Middlefork Irrigation District |
| MLP | Mount Lassen Power |
| MONT | Monterey County Flood Center & Water Conservation |
| MPCC | Mount Poso Cogeneration Co. |
| MPLP | Midsun Partners, L.P. |
| MSCC | Midway Sunset Cogen Co. |
| MTEH | Mount Elbert Hydro |
| MVDI | Marsh Valley Development, Inc. |
| MWWR | Metropolitan Waste Water Reclamation District |
| NCPI | Nelson Creek Power, Inc. |
| NEI | Northwind Energy, Inc. |
| NFS | North Fork Sprague |
| NGCE | NGC Energy Systems, Inc. (Agrico Cogeneration) |
| NID | Nevada Irrigation District |
| NOVE | Nove Investments, Inc. |
| NSFH | NID & Scotts Flat Hydro |
| NTUA | Navajo Tribal Utility Authority |
| NUEV | Nuevo Energy Co. |
| NWPC | Northwest Pipeline Corp. |
| OCP | Oildale Cogeneration Partners, L.P. |
| OLSE | OLS Energy Berkeley |
| OPPI | Olsen Power Partners, Inc. |
| OSH | Opal Springs Hydro |
| OTCC | Oregon Trail Electric Consumer Coop, Inc. |
| OWD | Olcese Water District |
| PACE | Pacific Energy |
| PACL | Pacific Lumber |
| PCLC | PUD No. 1 of Clark County |
| PCOC | PUD No. 1 of Cowlitz County |
| PCU | Price City Utilities |

## Abbreviations Used

| | |
|---|---|
| PKCO | PUD No. 1 of Kittitas County |
| PLGC | Palo Alto Landfill Gas Corp. |
| POKC | PUD No. 1 of Okanogan County |
| POP | Pacific Oroville Power |
| POUL | Poulsbo Port District |
| PPC | POSDEF Power Co., L.P. |
| PPW | Patterson Pass Windfarm, L.L.C. |
| PRC | Power Resources Coop. |
| PUCH | Pacific Ultrapower Chinese |
| RBN | Ross, Burgess Norman |
| RBP | Rio Bravo Poso |
| RDNG | Redding Electric Dept. |
| RIPC | Ripon Cogeneration, Inc. |
| RPBC | Rhone-Poulenc Basic Chemicals |
| RVSD | Riverside Utilities Dept. |
| RWPC | Redlands Water & Power Co. |
| SCCC | Sargent Canyon Cogeneration Co. |
| SCHA | Slate Creek Hydro Assoc., L.P. |
| SCOG | Stockton Cogeneration Co. |
| SCPI | Shell California Production, Inc. |
| SCWA | Sonoma County Water Agency |
| SDC | Steamboat Development Corp. |
| SDCH | Stauffer Dry Creek Hydro |
| SEAT | Seattle, Port of |
| SEAW | Seawest Windfarms, Inc. |
| SEHA | SEH America, Inc. |
| SES | Steamboat Environ Systems |
| SGS | Star Group Stillwater I |
| SISK | Lake Siskiyou |
| SJC | San Jose Cogeneration |
| SJCL | San Joaquin CoGen, Ltd. |
| SJID | South San Joaquin Irrigation District |
| SJPC | San Joaquin Power Co. |
| SKAG | Skagit County, Port of |
| SMHL | Snow Mountain Hydro, L.L.C. |
| SNPD | PUD No. 1 of Snohomish County |
| SODA | Soda Lake, L.P. |
| SPII | Sierra Pacific Industries, Inc. |
| SRCC | Salinas River Cogeneration Co. |
| STAGE | Stagecoach |
| STSH | STS Hydropower, Ltd. |
| SUB | Springfield Utility Board |
| SUNH | Sunshine Hydro |
| SVP | Silicon Valley Power |
| SWE | Stanislaus Waste Energy |
| TCI | Truckee Carson Irrigation |
| TDPA | Tri-Dam Power Authority |
| TEDP | Thermal Energy Development Partners, L.P. |
| TEXO | Texaco Oil |

## Abbreviations Used

| | |
|---|---|
| THCI | Thermo Carbonic, Inc. |
| THII | Thermo Industries, Inc. |
| TKO | TKO |
| TOPM | Texas-Ohio Power Marketing, Inc. |
| TOSH | Toshiba America, Inc. |
| TOUA | Tohono O'Odham Utility Authority |
| TPUD | Truckee-Donner Public Utility District |
| UCO | University of Colorado |
| UCOG | United Cogen, Inc. |
| UMPA | Utah Municipal Power Agency |
| UNCO | University of Northern Colorado |
| USMV | USBIA-Mission Valley Power |
| VLPD | Vernon Light & Power Dept. |
| WAFE | Wafertech |
| WBC | WEA Baker Creek |
| WBPL | Woodland Biomass Power, Ltd. |
| WELP | Wadham Energy, L.P. |
| WICK | Wickenburg Utilities System |
| WILL | Williams, City of |
| WLI | Wheelabrator Lassen, Inc. |
| WMI | WindMaster, Inc. |
| WSPE | Warm Springs Power Enterprises |
| WTI | Wheelabrator Technologies, Inc. |
| YAMP | Yampa Valley Electric Assoc., Inc. |
| YANK | Yankee Caithness Joint Venture, L.P. |
| YCA | Yountville Cogeneration Assoc. |
| YCCP | Yuba City Cogen Partners, L.P. |
| YCWA | Yuba County Water Agency |
| YEPI | Yolo Energy Partners, Inc. |
| YTID | Yakima-Tieton Irrigation District |
| ZOND | Zond Systems, Inc. |

Competitive Analysis Screening Model (CASm v7.3)

# Transmission Report
# APS Market Power Analysis (Base Case)

Destination APS (APS)
Load Type Summer Super Peak

| From | To | BASE Limit (MW) | Flow (MW) |
|---|---|---|---|
| AEPC | WALC | 90000 | 326 |
| AES_CA_S | SCE | 90000 | 96 |
| ANHM | SCE | 90000 | 1002 |
| BEPC | WACM | 90000 | 5 |
| BHPL | WACM | 90000 | 3 |
| CGC_CA_N | PG_E | 90000 | 0 |
| CSU | WACM | 90000 | 4 |
| DGT | WACM | 90000 | 2 |
| DUK_CA_N | PG_E | 90000 | 0 |
| EPE | TEP | 519 | 177 |
| FCORN | APS | 1340 | 1340 |
| FCORN | NAVAJO | 1903 | 11 |
| FCORN | TEP | 1554 | 199 |
| FC_APS | FCORN | 90000 | 299 |
| FC_EPE | FCORN | 90000 | 35 |
| FC_PNM | FCORN | 90000 | 65 |
| FC_SCE | FCORN | 90000 | 239 |
| FC_SRP | FCORN | 90000 | 50 |
| HOU_CA_S | SCE | 90000 | 90 |
| ICPA | PACE | 90000 | 12 |
| IID | PVERDE | 1 | 1 |
| IID | SCE | 600 | 13 |
| IPC | WACM | 768 | 48 |
| LDWP | WALC | 2410 | 1272 |
| MPC | IPC | 2 | 2 |
| MPC | PACE | 400 | 1 |
| NAVAJO | APS | 2264 | 2264 |
| NAV_APS | NAVAJO | 90000 | 164 |
| NAV_LDWP | NAVAJO | 90000 | 162 |
| NAV_NEVP | NAVAJO | 90000 | 86 |
| NAV_SRP | NAVAJO | 90000 | 352 |
| NCPA | PG_E | 90000 | 0 |
| NEVP | WALC | 90000 | 1432 |
| NRG_CA_S | SCE | 90000 | 48 |
| PACE | FCORN | 600 | 559 |
| PASA | SCE | 90000 | 7 |
| PEGT | EPE | 90000 | 20 |
| PG_E | SCE | 3000 | 85 |
| PNM | FCORN | 597 | 196 |
| PNM | TEP | 224 | 224 |
| PPL_MT | MPC | 90000 | 0 |
| PRPA | WACM | 90000 | 3 |

Note: Limits of 90,000 MW indicate unconstrained flows.

Competitive Analysis Screening Model (CASm v7.3)

## Transmission Report
## APS Market Power Analysis (Base Case)

| | | | |
|---|---|---|---|
| PVERDE | APS | 3810 | 3810 |
| PV_APS | PVERDE | 90000 | 805 |
| PV_EPE | PVERDE | 90000 | 499 |
| PV_IID | PVERDE | 90000 | 12 |
| PV_LDWP | PVERDE | 90000 | 305 |
| PV_PASA | PVERDE | 90000 | 8 |
| PV_PNM | PVERDE | 90000 | 322 |
| PV_PVER_MO | PVERDE | 90000 | 42 |
| PV_SCE | PVERDE | 90000 | 499 |
| PV_SRP | PVERDE | 90000 | 358 |
| SCE | NAVAJO | 1505 | 805 |
| SCE | PVERDE | 1011 | 988 |
| SDGE | SCE | 2440 | 69 |
| SEI_CA_N | PG_E | 90000 | 0 |
| SPP | IPC | 192 | 5 |
| SRP | APS | 90000 | 3134 |
| TCK_CA_S | SCE | 90000 | 7 |
| TEP | APS | 672 | 672 |
| TEP | SRP | 672 | 593 |
| TSGT | WACM | 90000 | 9 |
| UPD_CA_S | SDGE | 90000 | 0 |
| WACM | FCORN | 200 | 132 |
| WALC | APS | 2800 | 2800 |
| WALC | NAVAJO | 6024 | 727 |
| WALC | SRP | 450 | 450 |

Note: Limits of 90,000 MW indicate unconstrained flows.

Competitive Analysis Screening Model (CASm v7.3)

## Transmission Report

## APS Market Power Analysis (Base Case)

Destination APS (APS)
Load Type Summer On-Peak

| From | To | BASE Limit (MW) | Flow (MW) |
|---|---|---|---|
| AEPC | WALC | 90000 | 264 |
| ANHM | SCE | 90000 | 1088 |
| BEPC | WACM | 90000 | 10 |
| BHPL | WACM | 90000 | 5 |
| CGC_CA_N | PG_E | 90000 | 0 |
| CSU | WACM | 90000 | 7 |
| DGT | WACM | 90000 | 4 |
| DUK_CA_N | PG_E | 90000 | 0 |
| EPE | TEP | 519 | 179 |
| FCORN | APS | 1340 | 1340 |
| FCORN | NAVAJO | 1903 | 788 |
| FCORN | TEP | 1554 | 214 |
| FC_APS | FCORN | 90000 | 521 |
| FC_EPE | FCORN | 90000 | 61 |
| FC_PNM | FCORN | 90000 | 113 |
| FC_SCE | FCORN | 90000 | 418 |
| FC_SRP | FCORN | 90000 | 87 |
| HOU_CA_S | SCE | 90000 | 59 |
| ICPA | PACE | 90000 | 17 |
| IID | PVERDE | 1 | 1 |
| IID | SCE | 600 | 14 |
| IPC | WACM | 768 | 69 |
| LDWP | WALC | 2410 | 1551 |
| MPC | IPC | 2 | 1 |
| NAVAJO | APS | 2264 | 2264 |
| NAV_APS | NAVAJO | 90000 | 91 |
| NAV_LDWP | NAVAJO | 90000 | 90 |
| NAV_NEVP | NAVAJO | 90000 | 48 |
| NAV_SRP | NAVAJO | 90000 | 194 |
| NCPA | PG_E | 90000 | 0 |
| NEVP | WALC | 90000 | 1411 |
| NRG_CA_S | SCE | 90000 | 26 |
| PACE | FCORN | 600 | 600 |
| PACE | NEVP | 300 | 185 |
| PACE | WALC | 250 | 250 |
| PASA | SCE | 90000 | 2 |
| PEGT | EPE | 90000 | 26 |
| PG_E | SCE | 3000 | 92 |
| PNM | FCORN | 597 | 380 |
| PNM | TEP | 224 | 224 |
| PPL_MT | MPC | 90000 | 0 |
| PRPA | WACM | 90000 | 6 |

Note: Limits of 90,000 MW indicate unconstrained flows.

Competitive Analysis Screening Model (CASm v7.3)

## Transmission Report

## APS Market Power Analysis (Base Case)

| | | | |
|---|---|---|---|
| PVERDE | APS | 3810 | 3810 |
| PV_APS | PVERDE | 90000 | 805 |
| PV_EPE | PVERDE | 90000 | 499 |
| PV_IID | PVERDE | 90000 | 12 |
| PV_LDWP | PVERDE | 90000 | 305 |
| PV_PASA | PVERDE | 90000 | 8 |
| PV_PNM | PVERDE | 90000 | 322 |
| PV_PVER_MO | PVERDE | 90000 | 42 |
| PV_SCE | PVERDE | 90000 | 499 |
| PV_SRP | PVERDE | 90000 | 358 |
| SCE | NAVAJO | 1505 | 759 |
| SCE | PVERDE | 1011 | 988 |
| SDGE | SCE | 2440 | 75 |
| SPP | IPC | 192 | 7 |
| SRP | APS | 90000 | 2867 |
| TEP | APS | 672 | 672 |
| TEP | SRP | 672 | 569 |
| TSGT | WACM | 90000 | 17 |
| WACM | FCORN | 200 | 195 |
| WALC | APS | 2800 | 2800 |
| WALC | NAVAJO | 6024 | 348 |
| WALC | SRP | 450 | 450 |

Note: Limits of 90,000 MW indicate unconstrained flows.

Competitive Analysis Screening Model (CASm v7.3)

## Transmission Report
## APS Market Power Analysis (Base Case)

Destination APS (APS)
Load Type Summer Off-Peak

| From | To | BASE Limit (MW) | Flow (MW) |
|---|---|---|---|
| AEPC | WALC | 90000 | 140 |
| ANHM | SCE | 90000 | 1415 |
| BEPC | WACM | 90000 | 11 |
| BHPL | WACM | 90000 | 5 |
| CGC_CA_N | PG_E | 90000 | 0 |
| CSU | WACM | 90000 | 8 |
| DGT | WACM | 90000 | 5 |
| EPE | TEP | 519 | 51 |
| FCORN | APS | 1340 | 1340 |
| FCORN | NAVAJO | 1903 | 547 |
| FCORN | TEP | 1554 | 284 |
| FC_APS | FCORN | 90000 | 644 |
| FC_EPE | FCORN | 90000 | 75 |
| FC_PNM | FCORN | 90000 | 140 |
| FC_SCE | FCORN | 90000 | 516 |
| FC_SRP | FCORN | 90000 | 108 |
| ICPA | PACE | 90000 | 17 |
| IID | PVERDE | 1 | 1 |
| IID | SCE | 600 | 12 |
| IPC | WACM | 768 | 71 |
| LDWP | WALC | 2410 | 1595 |
| MPC | IPC | 2 | 1 |
| NAVAJO | APS | 2264 | 2264 |
| NAV_APS | NAVAJO | 90000 | 342 |
| NAV_LDWP | NAVAJO | 90000 | 337 |
| NAV_NEVP | NAVAJO | 90000 | 180 |
| NAV_SRP | NAVAJO | 90000 | 731 |
| NCPA | PG_E | 90000 | 0 |
| NEVP | WALC | 90000 | 905 |
| PACE | LDWP | 1200 | 346 |
| PACE | NEVP | 300 | 300 |
| PACE | WALC | 250 | 250 |
| PASA | SCE | 90000 | 3 |
| PEGT | EPE | 90000 | 53 |
| PG_E | SCE | 3000 | 120 |
| PNM | FCORN | 597 | 509 |
| PNM | TEP | 224 | 224 |
| PPL_MT | MPC | 90000 | 0 |
| PRPA | WACM | 90000 | 7 |
| PVERDE | APS | 3810 | 3810 |
| PV_APS | PVERDE | 90000 | 805 |
| PV_EPE | PVERDE | 90000 | 499 |

Note: Limits of 90,000 MW indicate unconstrained flows.

Competitive Analysis Screening Model (CASm v7.3)

**Transmission Report**

**APS Market Power Analysis (Base Case)**

| | | | |
|---|---|---|---|
| PV_IID | PVERDE | 90000 | 12 |
| PV_LDWP | PVERDE | 90000 | 305 |
| PV_PASA | PVERDE | 90000 | 8 |
| PV_PNM | PVERDE | 90000 | 322 |
| PV_PVER_MO | PVERDE | 90000 | 42 |
| PV_SCE | PVERDE | 90000 | 499 |
| PV_SRP | PVERDE | 90000 | 358 |
| SCE | LDWP | 550 | 550 |
| SCE | NAVAJO | 1505 | 147 |
| SCE | PVERDE | 1011 | 988 |
| SCE | WALC | 602 | 374 |
| SDGE | SCE | 2440 | 98 |
| SPP | IPC | 192 | 7 |
| SRP | APS | 90000 | 2109 |
| TEP | APS | 672 | 672 |
| TEP | SRP | 672 | 514 |
| TSGT | WACM | 90000 | 19 |
| WACM | FCORN | 200 | 198 |
| WALC | APS | 2800 | 2800 |
| WALC | SRP | 450 | 450 |

Note: Limits of 90,000 MW indicate unconstrained flows.

Competitive Analysis Screening Model (CASm v7.3)

## Transmission Report
## APS Market Power Analysis (Base Case)

Destination APS (APS)
Load Type Winter Super Peak

| From | To | BASE Limit (MW) | Flow (MW) |
|---|---|---|---|
| AEPC | WALC | 90000 | 307 |
| AES_CA_S | SCE | 90000 | 92 |
| ANHM | SCE | 90000 | 958 |
| BEPC | WACM | 90000 | 8 |
| BHPL | WACM | 90000 | 5 |
| CGC_CA_N | PG_E | 90000 | 0 |
| CSU | WACM | 90000 | 6 |
| DGT | WACM | 90000 | 3 |
| DUK_CA_N | PG_E | 90000 | 0 |
| EPE | TEP | 519 | 178 |
| FCORN | APS | 1340 | 1340 |
| FCORN | NAVAJO | 1903 | 784 |
| FCORN | TEP | 1554 | 182 |
| FC_APS | FCORN | 90000 | 516 |
| FC_EPE | FCORN | 90000 | 60 |
| FC_PNM | FCORN | 90000 | 112 |
| FC_SCE | FCORN | 90000 | 414 |
| FC_SRP | FCORN | 90000 | 86 |
| HOU_CA_S | SCE | 90000 | 87 |
| ICPA | PACE | 90000 | 16 |
| IID | SCE | 600 | 12 |
| IPC | WACM | 869 | 67 |
| LDWP | WALC | 2410 | 1301 |
| MPC | IPC | 9 | 3 |
| NAVAJO | APS | 2264 | 2264 |
| NAV_APS | NAVAJO | 90000 | 91 |
| NAV_LDWP | NAVAJO | 90000 | 90 |
| NAV_NEVP | NAVAJO | 90000 | 48 |
| NAV_SRP | NAVAJO | 90000 | 194 |
| NCPA | PG_E | 90000 | 0 |
| NEVP | WALC | 90000 | 1382 |
| NRG_CA_S | SCE | 90000 | 46 |
| PACE | FCORN | 600 | 600 |
| PACE | WALC | 250 | 67 |
| PASA | SCE | 90000 | 7 |
| PEGT | EPE | 90000 | 20 |
| PG_E | SCE | 3000 | 81 |
| PNM | FCORN | 597 | 353 |
| PNM | TEP | 224 | 224 |
| PPL_MT | MPC | 90000 | 0 |
| PRPA | WACM | 90000 | 5 |
| PVERDE | APS | 3810 | 3810 |

Note: Limits of 90,000 MW indicate unconstrained flows.

Competitive Analysis Screening Model (CASm v7.3)

## Transmission Report

## APS Market Power Analysis (Base Case)

| | | | |
|---|---|---|---|
| PV_APS | PVERDE | 90000 | 807 |
| PV_EPE | PVERDE | 90000 | 501 |
| PV_IID | PVERDE | 90000 | 12 |
| PV_LDWP | PVERDE | 90000 | 306 |
| PV_PASA | PVERDE | 90000 | 8 |
| PV_PNM | PVERDE | 90000 | 323 |
| PV_PVER_MO | PVERDE | 90000 | 42 |
| PV_SCE | PVERDE | 90000 | 501 |
| PV_SRP | PVERDE | 90000 | 359 |
| SCE | NAVAJO | 1505 | 558 |
| SCE | PVERDE | 1011 | 979 |
| SDGE | SCE | 2440 | 66 |
| SEI_CA_N | PG_E | 90000 | 0 |
| SPP | IPC | 158 | 6 |
| SRP | APS | 90000 | 3182 |
| TCK_CA_S | SCE | 90000 | 7 |
| TEP | APS | 672 | 672 |
| TEP | SRP | 672 | 577 |
| TSGT | WACM | 90000 | 14 |
| UPD_CA_S | SDGE | 90000 | 0 |
| WACM | FCORN | 200 | 196 |
| WALC | APS | 2800 | 2800 |
| WALC | NAVAJO | 6024 | 552 |
| WALC | SRP | 450 | 450 |

Note: Limits of 90,000 MW indicate unconstrained flows.

Competitive Analysis Screening Model (CASm v7.3)

## Transmission Report

## APS Market Power Analysis (Base Case)

Destination APS (APS)
Load Type Winter On-Peak

| From | To | BASE Limit (MW) | Flow (MW) |
|---|---|---|---|
| AEPC | WALC | 90000 | 305 |
| ANHM | SCE | 90000 | 1138 |
| BEPC | WACM | 90000 | 10 |
| BHPL | WACM | 90000 | 5 |
| CGC_CA_N | PG_E | 90000 | 0 |
| CSU | WACM | 90000 | 7 |
| DGT | WACM | 90000 | 4 |
| DUK_CA_N | PG_E | 90000 | 0 |
| EPE | TEP | 519 | 179 |
| FCORN | APS | 1340 | 1340 |
| FCORN | NAVAJO | 1903 | 824 |
| FCORN | TEP | 1554 | 205 |
| FC_APS | FCORN | 90000 | 529 |
| FC_EPE | FCORN | 90000 | 62 |
| FC_PNM | FCORN | 90000 | 115 |
| FC_SCE | FCORN | 90000 | 424 |
| FC_SRP | FCORN | 90000 | 88 |
| HOU_CA_S | SCE | 90000 | 61 |
| ICPA | PACE | 90000 | 18 |
| IID | SCE | 600 | 14 |
| IPC | WACM | 869 | 73 |
| LDWP | WALC | 2410 | 1357 |
| MPC | IPC | 9 | 1 |
| NAVAJO | APS | 2264 | 2264 |
| NAV_APS | NAVAJO | 90000 | 98 |
| NAV_LDWP | NAVAJO | 90000 | 96 |
| NAV_NEVP | NAVAJO | 90000 | 51 |
| NAV_SRP | NAVAJO | 90000 | 209 |
| NCPA | PG_E | 90000 | 0 |
| NEVP | WALC | 90000 | 1746 |
| NRG_CA_S | SCE | 90000 | 27 |
| PACE | FCORN | 600 | 600 |
| PACE | LDWP | 1200 | 92 |
| PACE | NEVP | 300 | 300 |
| PACE | WALC | 250 | 250 |
| PASA | SCE | 90000 | 3 |
| PEGT | EPE | 90000 | 26 |
| PG_E | SCE | 3000 | 96 |
| PNM | FCORN | 597 | 386 |
| PNM | TEP | 224 | 224 |
| PPL_MT | MPC | 90000 | 0 |
| PRPA | WACM | 90000 | 6 |

Note: Limits of 90,000 MW indicate unconstrained flows.

Competitive Analysis Screening Model (CASm v7.3)

## Transmission Report

## APS Market Power Analysis (Base Case)

| | | | |
|---|---|---|---|
| PVERDE | APS | 3810 | 3810 |
| PV_APS | PVERDE | 90000 | 807 |
| PV_EPE | PVERDE | 90000 | 501 |
| PV_IID | PVERDE | 90000 | 12 |
| PV_LDWP | PVERDE | 90000 | 306 |
| PV_PASA | PVERDE | 90000 | 8 |
| PV_PNM | PVERDE | 90000 | 323 |
| PV_PVER_MO | PVERDE | 90000 | 42 |
| PV_SCE | PVERDE | 90000 | 501 |
| PV_SRP | PVERDE | 90000 | 359 |
| SCE | NAVAJO | 1505 | 621 |
| SCE | PVERDE | 1011 | 979 |
| SDGE | SCE | 2440 | 78 |
| SPP | IPC | 158 | 7 |
| SRP | APS | 90000 | 2875 |
| TEP | APS | 672 | 672 |
| TEP | SRP | 672 | 560 |
| TSGT | WACM | 90000 | 17 |
| WACM | FCORN | 200 | 198 |
| WALC | APS | 2800 | 2800 |
| WALC | NAVAJO | 6024 | 417 |
| WALC | SRP | 450 | 450 |

Note: Limits of 90,000 MW indicate unconstrained flows.

Competitive Analysis Screening Model (CASm v7.3)

## Transmission Report
## APS Market Power Analysis (Base Case)

Destination APS (APS)
Load Type Winter Off-Peak

| From | To | BASE Limit (MW) | Flow (MW) |
|---|---|---|---|
| ANHM | SCE | 90000 | 1546 |
| BHPL | WACM | 90000 | 1 |
| CGC_CA_N | PG_E | 90000 | 0 |
| CSU | WACM | 90000 | 2 |
| DGT | WACM | 90000 | 3 |
| FCORN | APS | 1340 | 1340 |
| FCORN | TEP | 1554 | 239 |
| FC_APS | FCORN | 90000 | 305 |
| FC_EPE | FCORN | 90000 | 97 |
| FC_PNM | FCORN | 90000 | 180 |
| FC_SCE | FCORN | 90000 | 665 |
| FC_SRP | FCORN | 90000 | 139 |
| IPC | PACE | 1100 | 140 |
| LDWP | WALC | 2410 | 559 |
| MPC | PACE | 400 | 3 |
| NAVAJO | APS | 2264 | 2264 |
| NAV_APS | NAVAJO | 90000 | 430 |
| NAV_LDWP | NAVAJO | 90000 | 424 |
| NAV_NEVP | NAVAJO | 90000 | 226 |
| NAV_SRP | NAVAJO | 90000 | 732 |
| NCPA | PG_E | 90000 | 0 |
| NEVP | WALC | 90000 | 718 |
| PACE | NEVP | 300 | 150 |
| PACE | WALC | 250 | 250 |
| PASA | SCE | 90000 | 0 |
| PG_E | SCE | 3000 | 132 |
| PPL_MT | MPC | 90000 | 0 |
| PVERDE | APS | 3810 | 3810 |
| PV_APS | PVERDE | 90000 | 807 |
| PV_EPE | PVERDE | 90000 | 501 |
| PV_IID | PVERDE | 90000 | 12 |
| PV_LDWP | PVERDE | 90000 | 306 |
| PV_PASA | PVERDE | 90000 | 8 |
| PV_PNM | PVERDE | 90000 | 323 |
| PV_PVER_MO | PVERDE | 90000 | 42 |
| PV_SCE | PVERDE | 90000 | 501 |
| PV_SRP | PVERDE | 90000 | 359 |
| SCE | NAVAJO | 1505 | 464 |
| SCE | PVERDE | 1011 | 979 |
| SCE | WALC | 602 | 602 |
| SDGE | SCE | 2440 | 108 |
| SPP | PACE | 150 | 29 |

Note: Limits of 90,000 MW indicate unconstrained flows.

Competitive Analysis Screening Model (CASm v7.3)

## Transmission Report
## APS Market Power Analysis (Base Case)

| | | | |
|---|---|---|---|
| SRP | APS | 90000 | 1425 |
| TEP | APS | 672 | 672 |
| TEP | SRP | 672 | 494 |
| WACM | FCORN | 200 | 200 |
| WACM | PACE | 785 | 74 |
| WALC | APS | 2800 | 1702 |
| WALC | SRP | 450 | 450 |

Note: Limits of 90,000 MW indicate unconstrained flows.

Competitive Analysis Screening Model (CASm v7.3)

## Transmission Report

## APS Market Power Analysis (Base Case)

Destination APS (APS)
Load Type Shoulder Super Peak

| From | To | BASE Limit (MW) | Flow (MW) |
|---|---|---|---|
| AEPC | WALC | 90000 | 311 |
| AES_CA_S | SCE | 90000 | 90 |
| ANHM | SCE | 90000 | 1050 |
| BEPC | WACM | 90000 | 5 |
| BHPL | WACM | 90000 | 3 |
| CGC_CA_N | PG_E | 90000 | 0 |
| CSU | WACM | 90000 | 4 |
| DGT | WACM | 90000 | 2 |
| DUK_CA_N | PG_E | 90000 | 0 |
| EPE | TEP | 519 | 185 |
| FCORN | APS | 1340 | 1340 |
| FCORN | NAVAJO | 1903 | 31 |
| FCORN | TEP | 1554 | 225 |
| FC_APS | FCORN | 90000 | 285 |
| FC_EPE | FCORN | 90000 | 33 |
| FC_PNM | FCORN | 90000 | 62 |
| FC_SCE | FCORN | 90000 | 228 |
| FC_SRP | FCORN | 90000 | 48 |
| HOU_CA_S | SCE | 90000 | 85 |
| ICPA | PACE | 90000 | 12 |
| IID | SCE | 600 | 13 |
| IPC | WACM | 822 | 54 |
| LDWP | WALC | 2410 | 1346 |
| MPC | IPC | 2 | 2 |
| MPC | PACE | 400 | 1 |
| NAVAJO | APS | 2264 | 2264 |
| NAV_APS | NAVAJO | 90000 | 157 |
| NAV_LDWP | NAVAJO | 90000 | 154 |
| NAV_NEVP | NAVAJO | 90000 | 82 |
| NAV_SRP | NAVAJO | 90000 | 335 |
| NCPA | PG_E | 90000 | 0 |
| NEVP | WALC | 90000 | 1398 |
| NRG_CA_S | SCE | 90000 | 46 |
| PACE | FCORN | 600 | 600 |
| PACE | WALC | 250 | 4 |
| PASA | SCE | 90000 | 7 |
| PEGT | EPE | 90000 | 20 |
| PG_E | SCE | 3000 | 89 |
| PNM | FCORN | 597 | 225 |
| PNM | TEP | 224 | 224 |
| PPL_MT | MPC | 90000 | 0 |
| PRPA | WACM | 90000 | 3 |

Note: Limits of 90,000 MW indicate unconstrained flows.

Competitive Analysis Screening Model (CASm v7.3)

## Transmission Report

## APS Market Power Analysis (Base Case)

| | | | |
|---|---|---|---|
| PVERDE | APS | 3810 | 3515 |
| PV_APS | PVERDE | 90000 | 715 |
| PV_EPE | PVERDE | 90000 | 443 |
| PV_IID | PVERDE | 90000 | 10 |
| PV_LDWP | PVERDE | 90000 | 271 |
| PV_PASA | PVERDE | 90000 | 7 |
| PV_PNM | PVERDE | 90000 | 286 |
| PV_PVER_MO | PVERDE | 90000 | 37 |
| PV_SCE | PVERDE | 90000 | 443 |
| PV_SRP | PVERDE | 90000 | 319 |
| SCE | NAVAJO | 1505 | 748 |
| SCE | PVERDE | 1011 | 1011 |
| SDGE | SCE | 2440 | 72 |
| SEI_CA_N | PG_E | 90000 | 0 |
| SPP | IPC | 233 | 5 |
| SRP | APS | 90000 | 2973 |
| TCK_CA_S | SCE | 90000 | 7 |
| TEP | APS | 672 | 672 |
| TEP | SRP | 672 | 592 |
| TSGT | WACM | 90000 | 9 |
| UPD_CA_S | SDGE | 90000 | 0 |
| WACM | FCORN | 200 | 143 |
| WALC | APS | 2800 | 2800 |
| WALC | NAVAJO | 6024 | 801 |
| WALC | SRP | 450 | 450 |

Note: Limits of 90,000 MW indicate unconstrained flows.

Competitive Analysis Screening Model (CASm v7.3)

# Transmission Report
# APS Market Power Analysis (Base Case)

Destination APS (APS)
Load Type Shoulder On-Peak

| From | To | BASE Limit (MW) | Flow (MW) |
|---|---|---|---|
| AEPC | WALC | 90000 | 131 |
| ANHM | SCE | 90000 | 859 |
| BEPC | WACM | 90000 | 7 |
| BHPL | WACM | 90000 | 4 |
| CGC_CA_N | PG_E | 90000 | 0 |
| CSU | WACM | 90000 | 5 |
| DGT | WACM | 90000 | 3 |
| EPE | TEP | 519 | 186 |
| FCORN | APS | 1340 | 1340 |
| FCORN | TEP | 1554 | 202 |
| FC_APS | FCORN | 90000 | 289 |
| FC_EPE | FCORN | 90000 | 34 |
| FC_PNM | FCORN | 90000 | 63 |
| FC_SCE | FCORN | 90000 | 232 |
| FC_SRP | FCORN | 90000 | 48 |
| ICPA | PACE | 90000 | 11 |
| IID | SCE | 600 | 11 |
| IPC | WACM | 822 | 53 |
| LDWP | WALC | 2410 | 910 |
| MPC | IPC | 2 | 0 |
| NAVAJO | FCORN | 1731 | 153 |
| NAVAJO | WALC | 6024 | 737 |
| NAV_APS | NAVAJO | 90000 | 176 |
| NAV_LDWP | NAVAJO | 90000 | 174 |
| NAV_NEVP | NAVAJO | 90000 | 93 |
| NAV_SRP | NAVAJO | 90000 | 377 |
| NCPA | PG_E | 90000 | 0 |
| NEVP | WALC | 90000 | 628 |
| PACE | FCORN | 600 | 357 |
| PACE | WALC | 250 | 250 |
| PASA | SCE | 90000 | 2 |
| PEGT | EPE | 90000 | 26 |
| PG_E | SCE | 3000 | 73 |
| PNM | FCORN | 597 | 256 |
| PNM | TEP | 224 | 224 |
| PPL_MT | MPC | 90000 | 0 |
| PRPA | WACM | 90000 | 4 |
| PVERDE | APS | 3810 | 3515 |
| PV_APS | PVERDE | 90000 | 715 |
| PV_EPE | PVERDE | 90000 | 443 |
| PV_IID | PVERDE | 90000 | 10 |
| PV_LDWP | PVERDE | 90000 | 271 |

Note: Limits of 90,000 MW indicate unconstrained flows.

Competitive Analysis Screening Model (CASm v7.3)

## Transmission Report
## APS Market Power Analysis (Base Case)

| | | | |
|---|---|---|---|
| PV_PASA | PVERDE | 90000 | 7 |
| PV_PNM | PVERDE | 90000 | 286 |
| PV_PVER_MO | PVERDE | 90000 | 37 |
| PV_SCE | PVERDE | 90000 | 443 |
| PV_SRP | PVERDE | 90000 | 319 |
| SCE | LDWP | 236 | 236 |
| SCE | NAVAJO | 1505 | 73 |
| SCE | PVERDE | 1011 | 1011 |
| SCE | WALC | 602 | 602 |
| SDGE | SCE | 2440 | 59 |
| SPP | IPC | 233 | 5 |
| SRP | APS | 90000 | 2650 |
| TEP | APS | 672 | 672 |
| TEP | SRP | 672 | 527 |
| TSGT | WACM | 90000 | 11 |
| WACM | FCORN | 200 | 135 |
| WALC | APS | 2800 | 2800 |
| WALC | SRP | 450 | 450 |

Note: Limits of 90,000 MW indicate unconstrained flows.

Competitive Analysis Screening Model (CASm v7.3)

## Transmission Report
## APS Market Power Analysis (Base Case)

Destination APS (APS)
Load Type Shoulder Off-Peak

| From | To | BASE Limit (MW) | Flow (MW) |
|---|---|---|---|
| ANHM | SCE | 90000 | 2223 |
| BHPL | WACM | 90000 | 5 |
| CSU | WACM | 90000 | 1 |
| DGT | WACM | 90000 | 1 |
| FCORN | APS | 1340 | 778 |
| IID | SCE | 600 | 1 |
| IPC | PACE | 1100 | 472 |
| LDWP | WALC | 2410 | 701 |
| MPC | IPC | 2 | 2 |
| MPC | PACE | 400 | 7 |
| NAVAJO | APS | 2264 | 1463 |
| NEVP | WALC | 90000 | 624 |
| PACE | FCORN | 600 | 600 |
| PACE | NEVP | 300 | 83 |
| PACE | WALC | 250 | 250 |
| PASA | SCE | 90000 | 0 |
| PPL_MT | MPC | 90000 | 0 |
| PVERDE | APS | 3810 | 3515 |
| PV_APS | PVERDE | 90000 | 715 |
| PV_EPE | PVERDE | 90000 | 443 |
| PV_IID | PVERDE | 90000 | 10 |
| PV_LDWP | PVERDE | 90000 | 271 |
| PV_PASA | PVERDE | 90000 | 7 |
| PV_PNM | PVERDE | 90000 | 286 |
| PV_PVER_MO | PVERDE | 90000 | 37 |
| PV_SCE | PVERDE | 90000 | 443 |
| PV_SRP | PVERDE | 90000 | 319 |
| SCE | LDWP | 236 | 236 |
| SCE | NAVAJO | 1505 | 1505 |
| SCE | PVERDE | 1011 | 1011 |
| SCE | WALC | 602 | 602 |
| SDGE | SCE | 2440 | 26 |
| SPP | IPC | 233 | 62 |
| SRP | APS | 90000 | 653 |
| WACM | FCORN | 200 | 200 |
| WACM | PACE | 785 | 334 |
| WALC | APS | 2800 | 1802 |
| WALC | SRP | 450 | 450 |

Note: Limits of 90,000 MW indicate unconstrained flows.

Competitive Analysis Screening Model (CASm v7.3)

## Transmission Report.
## APS Market Power Analysis (Including expected 2001 constructions)

Destination APS (APS)
Load Type Summer Super Peak

| From | To | BASE Limit (MW) | Flow (MW) |
|---|---|---|---|
| AEPC | WALC | 90000 | 287 |
| AES_CA_S | SCE | 90000 | 94 |
| ANHM | SCE | 90000 | 984 |
| BEPC | WACM | 90000 | 6 |
| BHPL | WACM | 90000 | 4 |
| CGC_CA_N | PG_E | 90000 | 0 |
| CGC_WALC | WALC | 90000 | 284 |
| CSU | WACM | 90000 | 5 |
| DGT | WACM | 90000 | 3 |
| DUK_CA_N | PG_E | 90000 | 0 |
| EPE | TEP | 519 | 177 |
| FCORN | APS | 1340 | 1340 |
| FCORN | TEP | 1554 | 200 |
| FC_APS | FCORN | 90000 | 298 |
| FC_EPE | FCORN | 90000 | 35 |
| FC_PNM | FCORN | 90000 | 65 |
| FC_SCE | FCORN | 90000 | 239 |
| FC_SRP | FCORN | 90000 | 50 |
| HOU_CA_S | SCE | 90000 | 89 |
| HOU_APS | APS | 90000 | 690 |
| HOU_WALC | WALC | 90000 | 273 |
| ICPA | PACE | 90000 | 11 |
| IID | PVERDE | 1 | 1 |
| IID | SCE | 600 | 13 |
| IPC | WACM | 768 | 48 |
| LDWP | PACE | 1400 | 41 |
| LDWP | WALC | 2410 | 1078 |
| MPC | IPC | 2 | 2 |
| MPC | PACE | 400 | 0 |
| NAVAJO | APS | 2264 | 2264 |
| NAV_APS | NAVAJO | 90000 | 167 |
| NAV_LDWP | NAVAJO | 90000 | 165 |
| NAV_NEVP | NAVAJO | 90000 | 88 |
| NAV_SRP | NAVAJO | 90000 | 358 |
| NCPA | PG_E | 90000 | 0 |
| NEVP | WALC | 90000 | 1261 |
| NRG_CA_S | SCE | 90000 | 47 |
| PACE | FCORN | 600 | 549 |
| PASA | SCE | 90000 | 7 |
| PEGT | EPE | 90000 | 20 |
| PG_E | SCE | 3000 | 83 |
| PNM | FCORN | 597 | 196 |

Note: Limits of 90,000 MW indicate unconstrained flows.

Competitive Analysis Screening Model (CASm v7.3)

## Transmission Report.

## APS Market Power Analysis (Including expected 2001 constructions)

| | | | |
|---|---|---|---|
| PNM | TEP | 224 | 224 |
| PPL_MT | MPC | 90000 | 0 |
| PRPA | WACM | 90000 | 4 |
| PVERDE | APS | 3810 | 3810 |
| PV_APS | PVERDE | 90000 | 805 |
| PV_EPE | PVERDE | 90000 | 499 |
| PV_IID | PVERDE | 90000 | 12 |
| PV_LDWP | PVERDE | 90000 | 305 |
| PV_PASA | PVERDE | 90000 | 8 |
| PV_PNM | PVERDE | 90000 | 322 |
| PV_PVER_MO | PVERDE | 90000 | 42 |
| PV_SCE | PVERDE | 90000 | 499 |
| PV_SRP | PVERDE | 90000 | 358 |
| SCE | NAVAJO | 1505 | 757 |
| SCE | PVERDE | 1011 | 988 |
| SDGE | SCE | 2440 | 68 |
| SEI_CA_N | PG_E | 90000 | 0 |
| SPP | IPC | 192 | 5 |
| SRP | APS | 90000 | 3134 |
| TCK_CA_S | SCE | 90000 | 7 |
| TEP | APS | 672 | 672 |
| TEP | SRP | 672 | 594 |
| UPD_CA_S | SDGE | 90000 | 0 |
| WACM | FCORN | 200 | 132 |
| WALC | APS | 2800 | 2800 |
| WALC | NAVAJO | 6024 | 772 |
| WALC | SRP | 450 | 450 |

Note: Limits of 90,000 MW indicate unconstrained flows.

Competitive Analysis Screening Model (CASm v7.3)

## Transmission Report.

## APS Market Power Analysis (Including expected 2001 constructions)

Destination APS (APS)
Load Type Summer On-Peak

| From | To | BASE Limit (MW) | Flow (MW) |
|---|---|---|---|
| AEPC | WALC | 90000 | 232 |
| ANHM | SCE | 90000 | 1067 |
| BEPC | WACM | 90000 | 13 |
| BHPL | WACM | 90000 | 6 |
| CGC_CA_N | PG_E | 90000 | 0 |
| CGC_WALC | WALC | 90000 | 271 |
| CSU | WACM | 90000 | 9 |
| DGT | WACM | 90000 | 5 |
| DUK_CA_N | PG_E | 90000 | 0 |
| EPE | TEP | 519 | 179 |
| FCORN | APS | 1340 | 1340 |
| FCORN | NAVAJO | 1903 | 783 |
| FCORN | TEP | 1554 | 219 |
| FC_APS | FCORN | 90000 | 520 |
| FC_EPE | FCORN | 90000 | 61 |
| FC_PNM | FCORN | 90000 | 113 |
| FC_SCE | FCORN | 90000 | 417 |
| FC_SRP | FCORN | 90000 | 87 |
| HOU_CA_S | SCE | 90000 | 58 |
| HOU_APS | APS | 90000 | 690 |
| HOU_WALC | WALC | 90000 | 261 |
| ICPA | PACE | 90000 | 16 |
| IID | PVERDE | 1 | 1 |
| IID | SCE | 600 | 14 |
| IPC | WACM | 768 | 70 |
| LDWP | WALC | 2410 | 1363 |
| MPC | IPC | 2 | 1 |
| NAVAJO | APS | 2264 | 2264 |
| NAV_APS | NAVAJO | 90000 | 91 |
| NAV_LDWP | NAVAJO | 90000 | 90 |
| NAV_NEVP | NAVAJO | 90000 | 48 |
| NAV_SRP | NAVAJO | 90000 | 194 |
| NCPA | PG_E | 90000 | 0 |
| NEVP | WALC | 90000 | 1173 |
| NRG_CA_S | SCE | 90000 | 26 |
| PACE | FCORN | 600 | 600 |
| PACE | NEVP | 300 | 92 |
| PACE | WALC | 250 | 250 |
| PASA | SCE | 90000 | 2 |
| PEGT | EPE | 90000 | 26 |
| PG_E | SCE | 3000 | 91 |
| PNM | FCORN | 597 | 379 |

Note: Limits of 90,000 MW indicate unconstrained flows.

Competitive Analysis Screening Model (CASm v7.3)

**Transmission Report.**

**APS Market Power Analysis (Including expected 2001 constructions)**

| | | | |
|---|---|---|---|
| PNM | TEP | 224 | 224 |
| PPL_MT | MPC | 90000 | 0 |
| PRPA | WACM | 90000 | 8 |
| PVERDE | APS | 3810 | 3810 |
| PV_APS | PVERDE | 90000 | 805 |
| PV_EPE | PVERDE | 90000 | 499 |
| PV_IID | PVERDE | 90000 | 12 |
| PV_LDWP | PVERDE | 90000 | 305 |
| PV_PASA | PVERDE | 90000 | 8 |
| PV_PNM | PVERDE | 90000 | 322 |
| PV_PVER_MO | PVERDE | 90000 | 42 |
| PV_SCE | PVERDE | 90000 | 499 |
| PV_SRP | PVERDE | 90000 | 358 |
| SCE | NAVAJO | 1505 | 703 |
| SCE | PVERDE | 1011 | 988 |
| SDGE | SCE | 2440 | 74 |
| SPP | IPC | 192 | 6 |
| SRP | APS | 90000 | 2872 |
| TEP | APS | 672 | 672 |
| TEP | SRP | 672 | 574 |
| WACM | FCORN | 200 | 198 |
| WALC | APS | 2800 | 2800 |
| WALC | NAVAJO | 6024 | 408 |
| WALC | SRP | 450 | 450 |

Note: Limits of 90,000 MW indicate unconstrained flows.

Competitive Analysis Screening Model (CASm v7.3)

## Transmission Report.

## APS Market Power Analysis (Including expected 2001 constructions)

Destination APS (APS)
Load Type Summer Off-Peak

| From | To | BASE Limit (MW) | Flow (MW) |
|---|---|---|---|
| AEPC | WALC | 90000 | 140 |
| ANHM | SCE | 90000 | 1415 |
| BEPC | WACM | 90000 | 15 |
| BHPL | WACM | 90000 | 7 |
| CGC_CA_N | PG_E | 90000 | 0 |
| CSU | WACM | 90000 | 11 |
| DGT | WACM | 90000 | 6 |
| EPE | TEP | 519 | 51 |
| FCORN | APS | 1340 | 1340 |
| FCORN | NAVAJO | 1903 | 542 |
| FCORN | TEP | 1554 | 288 |
| FC_APS | FCORN | 90000 | 643 |
| FC_EPE | FCORN | 90000 | 75 |
| FC_PNM | FCORN | 90000 | 140 |
| FC_SCE | FCORN | 90000 | 516 |
| FC_SRP | FCORN | 90000 | 107 |
| ICPA | PACE | 90000 | 17 |
| IID | PVERDE | 1 | 1 |
| IID | SCE | 600 | 12 |
| IPC | WACM | 768 | 70 |
| LDWP | WALC | 2410 | 1600 |
| MPC | PACE | 400 | 1 |
| NAVAJO | APS | 2264 | 2264 |
| NAV_APS | NAVAJO | 90000 | 342 |
| NAV_LDWP | NAVAJO | 90000 | 337 |
| NAV_NEVP | NAVAJO | 90000 | 180 |
| NAV_SRP | NAVAJO | 90000 | 731 |
| NCPA | PG_E | 90000 | 0 |
| NEVP | WALC | 90000 | 905 |
| PACE | LDWP | 1200 | 351 |
| PACE | NEVP | 300 | 300 |
| PACE | WALC | 250 | 250 |
| PASA | SCE | 90000 | 3 |
| PEGT | EPE | 90000 | 53 |
| PG_E | SCE | 3000 | 120 |
| PNM | FCORN | 597 | 509 |
| PNM | TEP | 224 | 224 |
| PPL_MT | MPC | 90000 | 0 |
| PRPA | WACM | 90000 | 10 |
| PVERDE | APS | 3810 | 3810 |
| PV_APS | PVERDE | 90000 | 805 |
| PV_EPE | PVERDE | 90000 | 499 |

Note: Limits of 90,000 MW indicate unconstrained flows.

Competitive Analysis Screening Model (CASm v7.3)

## Transmission Report.

## APS Market Power Analysis (Including expected 2001 constructions)

| | | | |
|---|---|---|---|
| PV_IID | PVERDE | 90000 | 12 |
| PV_LDWP | PVERDE | 90000 | 305 |
| PV_PASA | PVERDE | 90000 | 8 |
| PV_PNM | PVERDE | 90000 | 322 |
| PV_PVER_MO | PVERDE | 90000 | 42 |
| PV_SCE | PVERDE | 90000 | 499 |
| PV_SRP | PVERDE | 90000 | 358 |
| SCE | LDWP | 550 | 550 |
| SCE | NAVAJO | 1505 | 152 |
| SCE | PVERDE | 1011 | 988 |
| SCE | WALC | 602 | 369 |
| SDGE | SCE | 2440 | 98 |
| SPP | IPC | 192 | 2 |
| SPP | PACE | 150 | 5 |
| SRP | APS | 90000 | 2113 |
| TEP | APS | 672 | 672 |
| TEP | SRP | 672 | 518 |
| WACM | FCORN | 200 | 200 |
| WALC | APS | 2800 | 2800 |
| WALC | SRP | 450 | 450 |

Note: Limits of 90,000 MW indicate unconstrained flows.

Competitive Analysis Screening Model (CASm v7.3)

## Transmission Report.
## APS Market Power Analysis (Including expected 2001 constructions)

Destination APS (APS)
Load Type Winter Super Peak

| From | To | BASE Limit (MW) | Flow (MW) |
|---|---|---|---|
| AEPC | WALC | 90000 | 271 |
| AES_CA_S | SCE | 90000 | 90 |
| ANHM | SCE | 90000 | 940 |
| BEPC | WACM | 90000 | 9 |
| BHPL | WACM | 90000 | 6 |
| CGC_CA_N | PG_E | 90000 | 0 |
| CGC_WALC | WALC | 90000 | 268 |
| CSU | WACM | 90000 | 8 |
| DGT | WACM | 90000 | 4 |
| DUK_CA_N | PG_E | 90000 | 0 |
| EPE | TEP | 519 | 178 |
| FCORN | APS | 1340 | 1340 |
| FCORN | NAVAJO | 1903 | 782 |
| FCORN | TEP | 1554 | 185 |
| FC_APS | FCORN | 90000 | 516 |
| FC_EPE | FCORN | 90000 | 60 |
| FC_PNM | FCORN | 90000 | 112 |
| FC_SCE | FCORN | 90000 | 413 |
| FC_SRP | FCORN | 90000 | 86 |
| HOU_CA_S | SCE | 90000 | 86 |
| HOU_APS | APS | 90000 | 690 |
| HOU_WALC | WALC | 90000 | 257 |
| ICPA | PACE | 90000 | 15 |
| IID | SCE | 600 | 11 |
| IPC | WACM | 869 | 67 |
| LDWP | WALC | 2410 | 1146 |
| MPC | IPC | 9 | 3 |
| MPC | PACE | 400 | 0 |
| NAVAJO | APS | 2264 | 2264 |
| NAV_APS | NAVAJO | 90000 | 91 |
| NAV_LDWP | NAVAJO | 90000 | 90 |
| NAV_NEVP | NAVAJO | 90000 | 48 |
| NAV_SRP | NAVAJO | 90000 | 194 |
| NCPA | PG_E | 90000 | 0 |
| NEVP | WALC | 90000 | 1218 |
| NRG_CA_S | SCE | 90000 | 46 |
| PACE | FCORN | 600 | 600 |
| PACE | WALC | 250 | 18 |
| PASA | SCE | 90000 | 7 |
| PEGT | EPE | 90000 | 20 |
| PG_E | SCE | 3000 | 80 |
| PNM | FCORN | 597 | 352 |

Note: Limits of 90,000 MW indicate unconstrained flows.

Competitive Analysis Screening Model (CASm v7.3)

## Transmission Report.

## APS Market Power Analysis (Including expected 2001 constructions)

| | | | |
|---|---|---|---|
| PNM | TEP | 224 | 224 |
| PPL_MT | MPC | 90000 | 0 |
| PRPA | WACM | 90000 | 6 |
| PVERDE | APS | 3810 | 3810 |
| PV_APS | PVERDE | 90000 | 807 |
| PV_EPE | PVERDE | 90000 | 501 |
| PV_IID | PVERDE | 90000 | 12 |
| PV_LDWP | PVERDE | 90000 | 306 |
| PV_PASA | PVERDE | 90000 | 8 |
| PV_PNM | PVERDE | 90000 | 323 |
| PV_PVER_MO | PVERDE | 90000 | 42 |
| PV_SCE | PVERDE | 90000 | 501 |
| PV_SRP | PVERDE | 90000 | 359 |
| SCE | NAVAJO | 1505 | 527 |
| SCE | PVERDE | 1011 | 979 |
| SDGE | SCE | 2440 | 65 |
| SEI_CA_N | PG_E | 90000 | 0 |
| SPP | IPC | 158 | 6 |
| SRP | APS | 90000 | 3185 |
| TCK_CA_S | SCE | 90000 | 7 |
| TEP | APS | 672 | 672 |
| TEP | SRP | 672 | 580 |
| UPD_CA_S | SDGE | 90000 | 0 |
| WACM | FCORN | 200 | 200 |
| WALC | APS | 2800 | 2800 |
| WALC | NAVAJO | 6024 | 585 |
| WALC | SRP | 450 | 450 |

Note: Limits of 90,000 MW indicate unconstrained flows.

Competitive Analysis Screening Model (CASm v7.3)

**Transmission Report.**

**APS Market Power Analysis (Including expected 2001 constructions)**

Destination APS (APS)
Load Type Winter On-Peak

| From | To | BASE Limit (MW) | Flow (MW) |
|---|---|---|---|
| AEPC | WALC | 90000 | 267 |
| ANHM | SCE | 90000 | 1094 |
| BEPC | WACM | 90000 | 13 |
| BHPL | WACM | 90000 | 6 |
| CGC_CA_N | PG_E | 90000 | 0 |
| CGC_WALC | WALC | 90000 | 313 |
| CSU | WACM | 90000 | 9 |
| DGT | WACM | 90000 | 6 |
| DUK_CA_N | PG_E | 90000 | 0 |
| EPE | TEP | 519 | 179 |
| FCORN | APS | 1340 | 1340 |
| FCORN | NAVAJO | 1903 | 795 |
| FCORN | TEP | 1554 | 210 |
| FC_APS | FCORN | 90000 | 521 |
| FC_EPE | FCORN | 90000 | 61 |
| FC_PNM | FCORN | 90000 | 113 |
| FC_SCE | FCORN | 90000 | 417 |
| FC_SRP | FCORN | 90000 | 87 |
| HOU_CA_S | SCE | 90000 | 59 |
| HOU_APS | APS | 90000 | 690 |
| HOU_WALC | WALC | 90000 | 300 |
| ICPA | PACE | 90000 | 17 |
| IID | SCE | 600 | 13 |
| IPC | WACM | 869 | 74 |
| LDWP | WALC | 2410 | 1112 |
| MPC | IPC | 9 | 1 |
| NAVAJO | APS | 2264 | 2264 |
| NAV_APS | NAVAJO | 90000 | 91 |
| NAV_LDWP | NAVAJO | 90000 | 90 |
| NAV_NEVP | NAVAJO | 90000 | 48 |
| NAV_SRP | NAVAJO | 90000 | 194 |
| NCPA | PG_E | 90000 | 0 |
| NEVP | WALC | 90000 | 1540 |
| NRG_CA_S | SCE | 90000 | 26 |
| PACE | FCORN | 600 | 600 |
| PACE | NEVP | 300 | 270 |
| PACE | WALC | 250 | 250 |
| PASA | SCE | 90000 | 2 |
| PEGT | EPE | 90000 | 26 |
| PG_E | SCE | 3000 | 93 |
| PNM | FCORN | 597 | 380 |
| PNM | TEP | 224 | 224 |

Note: Limits of 90,000 MW indicate unconstrained flows.

Competitive Analysis Screening Model (CASm v7.3)

## Transmission Report.

## APS Market Power Analysis (Including expected 2001 constructions)

| | | | |
|---|---|---|---|
| PPL_MT | MPC | 90000 | 0 |
| PRPA | WACM | 90000 | 8 |
| PVERDE | APS | 3810 | 3810 |
| PV_APS | PVERDE | 90000 | 807 |
| PV_EPE | PVERDE | 90000 | 501 |
| PV_IID | PVERDE | 90000 | 12 |
| PV_LDWP | PVERDE | 90000 | 306 |
| PV_PASA | PVERDE | 90000 | 8 |
| PV_PNM | PVERDE | 90000 | 323 |
| PV_PVER_MO | PVERDE | 90000 | 42 |
| PV_SCE | PVERDE | 90000 | 501 |
| PV_SRP | PVERDE | 90000 | 359 |
| SCE | NAVAJO | 1505 | 558 |
| SCE | PVERDE | 1011 | 979 |
| SDGE | SCE | 2440 | 75 |
| SPP | IPC | 158 | 7 |
| SRP | APS | 90000 | 2880 |
| TEP | APS | 672 | 672 |
| TEP | SRP | 672 | 565 |
| WACM | FCORN | 200 | 199 |
| WALC | APS | 2800 | 2800 |
| WALC | NAVAJO | 6024 | 542 |
| WALC | SRP | 450 | 450 |

Note: Limits of 90,000 MW indicate unconstrained flows.

Competitive Analysis Screening Model (CASm v7.3)

**Transmission Report.**

**APS Market Power Analysis (Including expected 2001 constructions)**

| | |
|---|---|
| Destination | APS (APS) |
| Load Type | Winter Off-Peak |

| From | To | BASE Limit (MW) | Flow (MW) |
|---|---|---|---|
| ANHM | SCE | 90000 | 1546 |
| BHPL | WACM | 90000 | 1 |
| CGC_CA_N | PG_E | 90000 | 0 |
| CSU | WACM | 90000 | 2 |
| DGT | WACM | 90000 | 3 |
| FCORN | APS | 1340 | 1340 |
| FCORN | TEP | 1554 | 237 |
| FC_APS | FCORN | 90000 | 305 |
| FC_EPE | FCORN | 90000 | 97 |
| FC_PNM | FCORN | 90000 | 180 |
| FC_SCE | FCORN | 90000 | 663 |
| FC_SRP | FCORN | 90000 | 138 |
| IPC | PACE | 1100 | 145 |
| LDWP | WALC | 2410 | 559 |
| MPC | PACE | 400 | 3 |
| NAVAJO | APS | 2264 | 2264 |
| NAV_APS | NAVAJO | 90000 | 430 |
| NAV_LDWP | NAVAJO | 90000 | 424 |
| NAV_NEVP | NAVAJO | 90000 | 226 |
| NAV_SRP | NAVAJO | 90000 | 732 |
| NCPA | PG_E | 90000 | 0 |
| NEVP | WALC | 90000 | 740 |
| PACE | NEVP | 300 | 173 |
| PACE | WALC | 250 | 250 |
| PASA | SCE | 90000 | 0 |
| PG_E | SCE | 3000 | 132 |
| PPL_MT | MPC | 90000 | 0 |
| PVERDE | APS | 3810 | 3810 |
| PV_APS | PVERDE | 90000 | 807 |
| PV_EPE | PVERDE | 90000 | 501 |
| PV_IID | PVERDE | 90000 | 12 |
| PV_LDWP | PVERDE | 90000 | 306 |
| PV_PASA | PVERDE | 90000 | 8 |
| PV_PNM | PVERDE | 90000 | 323 |
| PV_PVER_MO | PVERDE | 90000 | 42 |
| PV_SCE | PVERDE | 90000 | 501 |
| PV_SRP | PVERDE | 90000 | 359 |
| SCE | NAVAJO | 1505 | 464 |
| SCE | PVERDE | 1011 | 979 |
| SCE | WALC | 602 | 602 |
| SDGE | SCE | 2440 | 108 |
| SPP | PACE | 150 | 29 |

Note: Limits of 90,000 MW indicate unconstrained flows.

Competitive Analysis Screening Model (CASm v7.3)

## Transmission Report.

## APS Market Power Analysis (Including expected 2001 constructions)

| | | | |
|---|---|---|---|
| SRP | APS | 90000 | 1422 |
| TEP | APS | 672 | 672 |
| TEP | SRP | 672 | 491 |
| WACM | FCORN | 200 | 200 |
| WACM | PACE | 785 | 93 |
| WALC | APS | 2800 | 1724 |
| WALC | SRP | 450 | 450 |

Note: Limits of 90,000 MW indicate unconstrained flows.

Competitive Analysis Screening Model (CASm v7.3)

## Transmission Report.
## APS Market Power Analysis (Including expected 2001 constructions)

Destination APS (APS)
Load Type Shoulder Super Peak

| From | To | BASE Limit (MW) | Flow (MW) |
|---|---|---|---|
| AEPC | WALC | 90000 | 273 |
| AES_CA_S | SCE | 90000 | 88 |
| ANHM | SCE | 90000 | 1031 |
| BEPC | WACM | 90000 | 6 |
| BHPL | WACM | 90000 | 4 |
| CGC_CA_N | PG_E | 90000 | 0 |
| CGC_WALC | WALC | 90000 | 287 |
| CSU | WACM | 90000 | 5 |
| DGT | WACM | 90000 | 3 |
| DUK_CA_N | PG_E | 90000 | 0 |
| EPE | TEP | 519 | 185 |
| FCORN | APS | 1340 | 1340 |
| FCORN | TEP | 1554 | 227 |
| FC_APS | FCORN | 90000 | 284 |
| FC_EPE | FCORN | 90000 | 33 |
| FC_PNM | FCORN | 90000 | 62 |
| FC_SCE | FCORN | 90000 | 228 |
| FC_SRP | FCORN | 90000 | 47 |
| HOU_CA_S | SCE | 90000 | 84 |
| HOU_APS | APS | 90000 | 678 |
| HOU_WALC | WALC | 90000 | 275 |
| ICPA | PACE | 90000 | 12 |
| IID | SCE | 600 | 13 |
| IPC | WACM | 822 | 53 |
| LDWP | PACE | 1400 | 21 |
| LDWP | WALC | 2410 | 1163 |
| MPC | IPC | 2 | 2 |
| MPC | PACE | 400 | 1 |
| NAVAJO | APS | 2264 | 2264 |
| NAV_APS | NAVAJO | 90000 | 159 |
| NAV_LDWP | NAVAJO | 90000 | 157 |
| NAV_NEVP | NAVAJO | 90000 | 84 |
| NAV_SRP | NAVAJO | 90000 | 341 |
| NCPA | PG_E | 90000 | 0 |
| NEVP | WALC | 90000 | 1230 |
| NRG_CA_S | SCE | 90000 | 45 |
| PACE | FCORN | 600 | 570 |
| PASA | SCE | 90000 | 7 |
| PEGT | EPE | 90000 | 20 |
| PG_E | SCE | 3000 | 87 |
| PNM | FCORN | 597 | 225 |
| PNM | TEP | 224 | 224 |

Note: Limits of 90,000 MW indicate unconstrained flows.

Competitive Analysis Screening Model (CASm v7.3)

## Transmission Report.
## APS Market Power Analysis (Including expected 2001 constructions)

| | | | |
|---|---|---|---|
| PPL_MT | MPC | 90000 | 0 |
| PRPA | WACM | 90000 | 4 |
| PVERDE | APS | 3810 | 3515 |
| PV_APS | PVERDE | 90000 | 715 |
| PV_EPE | PVERDE | 90000 | 443 |
| PV_IID | PVERDE | 90000 | 10 |
| PV_LDWP | PVERDE | 90000 | 271 |
| PV_PASA | PVERDE | 90000 | 7 |
| PV_PNM | PVERDE | 90000 | 286 |
| PV_PVER_MO | PVERDE | 90000 | 37 |
| PV_SCE | PVERDE | 90000 | 443 |
| PV_SRP | PVERDE | 90000 | 319 |
| SCE | NAVAJO | 1505 | 708 |
| SCE | PVERDE | 1011 | 1011 |
| SDGE | SCE | 2440 | 71 |
| SEI_CA_N | PG_E | 90000 | 0 |
| SPP | IPC | 233 | 5 |
| SRP | APS | 90000 | 2975 |
| TCK_CA_S | SCE | 90000 | 7 |
| TEP | APS | 672 | 672 |
| TEP | SRP | 672 | 593 |
| UPD_CA_S | SDGE | 90000 | 0 |
| WACM | FCORN | 200 | 144 |
| WALC | APS | 2800 | 2800 |
| WALC | NAVAJO | 6024 | 859 |
| WALC | SRP | 450 | 450 |

Note: Limits of 90,000 MW indicate unconstrained flows.

Competitive Analysis Screening Model (CASm v7.3)

## Transmission Report.
## APS Market Power Analysis (Including expected 2001 constructions)

Destination APS (APS)
Load Type Shoulder On-Peak

| From | To | BASE Limit (MW) | Flow (MW) |
|---|---|---|---|
| AEPC | WALC | 90000 | 119 |
| ANHM | SCE | 90000 | 848 |
| BEPC | WACM | 90000 | 9 |
| BHPL | WACM | 90000 | 5 |
| CGC_CA_N | PG_E | 90000 | 0 |
| CGC_WALC | WALC | 90000 | 149 |
| CSU | WACM | 90000 | 6 |
| DGT | WACM | 90000 | 4 |
| EPE | TEP | 519 | 187 |
| FCORN | APS | 1340 | 1340 |
| FCORN | TEP | 1554 | 208 |
| FC_APS | FCORN | 90000 | 289 |
| FC_EPE | FCORN | 90000 | 34 |
| FC_PNM | FCORN | 90000 | 63 |
| FC_SCE | FCORN | 90000 | 232 |
| FC_SRP | FCORN | 90000 | 48 |
| HOU_APS | APS | 90000 | 678 |
| HOU_WALC | WALC | 90000 | 143 |
| ICPA | PACE | 90000 | 11 |
| IID | SCE | 600 | 11 |
| IPC | WACM | 822 | 54 |
| LDWP | WALC | 2410 | 848 |
| MPC | IPC | 2 | 0 |
| NAVAJO | FCORN | 1731 | 199 |
| NAVAJO | WALC | 6024 | 576 |
| NAV_APS | NAVAJO | 90000 | 166 |
| NAV_LDWP | NAVAJO | 90000 | 164 |
| NAV_NEVP | NAVAJO | 90000 | 87 |
| NAV_SRP | NAVAJO | 90000 | 355 |
| NCPA | PG_E | 90000 | 0 |
| NEVP | WALC | 90000 | 571 |
| PACE | FCORN | 600 | 317 |
| PACE | WALC | 250 | 250 |
| PASA | SCE | 90000 | 2 |
| PEGT | EPE | 90000 | 26 |
| PG_E | SCE | 3000 | 72 |
| PNM | FCORN | 597 | 255 |
| PNM | TEP | 224 | 224 |
| PPL_MT | MPC | 90000 | 0 |
| PRPA | WACM | 90000 | 6 |
| PVERDE | APS | 3810 | 3515 |
| PV_APS | PVERDE | 90000 | 715 |

Note: Limits of 90,000 MW indicate unconstrained flows.

Competitive Analysis Screening Model (CASm v7.3)

## Transmission Report.

## APS Market Power Analysis (Including expected 2001 constructions)

| | | | |
|---|---|---|---|
| PV_EPE | PVERDE | 90000 | 443 |
| PV_IID | PVERDE | 90000 | 10 |
| PV_LDWP | PVERDE | 90000 | 271 |
| PV_PASA | PVERDE | 90000 | 7 |
| PV_PNM | PVERDE | 90000 | 286 |
| PV_PVER_MO | PVERDE | 90000 | 37 |
| PV_SCE | PVERDE | 90000 | 443 |
| PV_SRP | PVERDE | 90000 | 319 |
| SCE | LDWP | 236 | 236 |
| SCE | NAVAJO | 1505 | 4 |
| SCE | PVERDE | 1011 | 1011 |
| SCE | WALC | 602 | 602 |
| SDGE | SCE | 2440 | 59 |
| SPP | IPC | 233 | 5 |
| SRP | APS | 90000 | 2656 |
| TEP | APS | 672 | 672 |
| TEP | SRP | 672 | 533 |
| WACM | FCORN | 200 | 137 |
| WALC | APS | 2800 | 2800 |
| WALC | SRP | 450 | 450 |

Note: Limits of 90,000 MW indicate unconstrained flows.

Competitive Analysis Screening Model (CASm v7.3)

# Transmission Report.

## APS Market Power Analysis (Including expected 2001 constructions)

Destination APS (APS)
Load Type Shoulder Off-Peak

| From | To | BASE Limit (MW) | Flow (MW) |
|---|---|---|---|
| ANHM | SCE | 90000 | 2223 |
| BHPL | WACM | 90000 | 6 |
| CSU | WACM | 90000 | 1 |
| DGT | WACM | 90000 | 1 |
| FCORN | APS | 1340 | 778 |
| IID | SCE | 600 | 1 |
| IPC | PACE | 1100 | 472 |
| LDWP | WALC | 2410 | 701 |
| MPC | IPC | 2 | 2 |
| MPC | PACE | 400 | 7 |
| NAVAJO | APS | 2264 | 1463 |
| NEVP | WALC | 90000 | 624 |
| PACE | FCORN | 600 | 600 |
| PACE | NEVP | 300 | 83 |
| PACE | WALC | 250 | 250 |
| PASA | SCE | 90000 | 0 |
| PPL_MT | MPC | 90000 | 0 |
| PVERDE | APS | 3810 | 3515 |
| PV_APS | PVERDE | 90000 | 715 |
| PV_EPE | PVERDE | 90000 | 443 |
| PV_IID | PVERDE | 90000 | 10 |
| PV_LDWP | PVERDE | 90000 | 271 |
| PV_PASA | PVERDE | 90000 | 7 |
| PV_PNM | PVERDE | 90000 | 286 |
| PV_PVER_MO | PVERDE | 90000 | 37 |
| PV_SCE | PVERDE | 90000 | 443 |
| PV_SRP | PVERDE | 90000 | 319 |
| SCE | LDWP | 236 | 236 |
| SCE | NAVAJO | 1505 | 1505 |
| SCE | PVERDE | 1011 | 1011 |
| SCE | WALC | 602 | 602 |
| SDGE | SCE | 2440 | 26 |
| SPP | IPC | 233 | 62 |
| SRP | APS | 90000 | 653 |
| WACM | FCORN | 200 | 200 |
| WACM | PACE | 785 | 334 |
| WALC | APS | 2800 | 1802 |
| WALC | SRP | 450 | 450 |

Note: Limits of 90,000 MW indicate unconstrained flows.

BEFORE THE

ARIZONA CORPORATION COMMISSION

REBUTTAL

TESTIMONY OF JOHN H. LANDON

On Behalf of

Arizona Public Service Company

Docket No. E-01345A-98-0473
Docket No. E-01345A-97-0773
Docket No. RE-00000C-94-0165

July 12, 1999

EXHIBIT
Admitted
APS-14

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## I. Introduction

**Q. Please state your name and business address.**

A. My name is John H. Landon. My address is Two Embarcadero Center, Suite 1160, San Francisco, California 94111.

**Q. Are you the same John Landon that submitted direct testimony in this proceeding?**

A. Yes, I am.

**Q. Please summarize the purpose of your rebuttal testimony.**

A. The Arizona Public Service Company (APS, or the Company) has asked me to respond to certain issues addressed by intervenors in their direct testimony on the proposed Settlement Agreement (Settlement). Specifically, I will respond to intervenors' concerns about the Settlement related to its effects on competition and the transfer of assets from APS to its FERC regulated affiliate.

## II. Settlement's Effects on Competition

### *A. Rate Reductions and the Goals of Competition*

**Q. Witness Oglesby claims that rate cuts agreed to by APS will "deter competition" (p. 10) because they will make it difficult for ESPs to offer a lower price for service than APS. Do you share his concern?**

A. No. The goal of regulatory policy should be to deliver competitive results for consumers without being unfair to producers. Competitive results include prices closer to the marginal cost of production and products and services better suited to consumer needs. Competitive markets will result in the long-term growth and prosperity of firms that deliver value to consumers and the decline and failure of those that do not.

**Q. What relation do these competitive objectives have to concerns expressed by Mr. Oglesby?**

A. The concerns do not appear to be focused on the interests of the consumer. Mr. Oglesby appears more concerned with the short-term financial interests of his company than with moving rapidly toward a more competitive result.

**Q. What do you see as the substantive issue that this witness raises?**

A. He appears to be in favor of higher prices by the incumbent and large credits for services provided by entrants, both of which would make entry more profitable and induce more customers to switch rapidly to alternative providers.

**Q. Isn't this consistent with having more effective competition?**

A. No. Competition is focused on the benefits to consumers and the long-run fairness of the playing field for producers. It does not focus on rules that will enhance the ability of entrants to profit at the expense of consumers and/or incumbent producers. Rate cuts are beneficial to consumers and, as long as rates cover at least marginal costs of production, are consistent with efficient competition. Requiring incumbents to charge higher rates and/or to provide credits for services bought from alternative suppliers that exceed marginal costs will financially advantage entrants at the expense of consumers and incumbent producers.

**Q. What is the real issue here?**

A. In my view, the real issue is whether we want to get to a fully competitive industry in Arizona quickly and at little cost to consumers or whether we want to delay the process and financially assist entrants by forcing consumers to accept higher current rates. Where, as here, there is the potential to create near-term benefits to consumers and still move to full competition in a relatively short period, I believe it is desirable to do so.

**Q. But if the difference between the access rate and the bundled rate is too small to be profitable for some entrants, isn't this a problem?**

A. While it is clearly a problem for the prospective entrants that don't find entry as profitable as they would like, it is not a problem in terms of consumer welfare, creating a level playing field or promoting an efficient level of entry. Getting through the transition period quickly so the state can enjoy all the fruits of competition is important. Moving rates to a level consistent with competition (e.g., marginal cost) is also important. Whether specific entrants will be able to profitably enter based on the initial difference between the access rate and the bundled rate is not of concern.

**Q. Witness Kingerski provides an example that purports to show that ESPs will not be able to compete with APS's Standard Offer tariff. (pp. 21-4) Have you reviewed this example?**

A. Yes I have.

**Q. Please briefly describe his analysis.**

A. Mr. Kingerski compares his estimate of the market price that ESPs will pay for energy (based on the Palo Verde NYMEX futures price), with his estimate of the shopping credits implicit in the bundled standard offer tariff for selected customers. The shopping credit is calculated by subtracting non-energy related charges from the bundled standard offer rate. He concludes that since the shopping credits are about equal to the ESP' commodity price that ESP's will be unable to compete with APS.

**Q. Do you agree with his conclusion?**

A. No. The fact that his computation of the ESP's commodity price is roughly equal to his computation of the shopping credit does not mean that EPSs will be unable to compete. An ESP would be able to compete, in the sense of making a contribution to fixed cost recovery, as long as its marginal cost is less than the market price. This is expected to be the case for efficient producers in the western United States. Moreover, the fact that the average Power Exchange (PX) price for California market is less than the shopping credit he computes suggests that this is clearly the case.

**Q. Are there any other examples where the shopping credits are roughly equal to the market price?**

A. Yes. This is the situation in California where the shopping credit is based on the Average Power Exchange price. Consequently, for California, the shopping credit and the market price are roughly equal.

**Q. Witness Kingerski suggests that a reduction of the CTC charge would help encourage competitive entry. (p. 24) What are the merits of this suggestion?**

A. Any merits are more than offset by the harm that reducing the CTC would inflict. If the level of the CTC falls, either the collection period must be extended to produce the same present value of collections or the amount collected would be reduced. A longer collection period would postpone the decline of energy costs to competitive levels. This delay would harm consumers by postponing the full benefits of competition. It would have no offsetting effect in lowering customer bills if larger credits merely resulted in higher cost entrants. Lower monthly CTCs would not guarantee lower prices to customers, but instead higher profits to competitors.

If lower CTC payments were not made up for by a longer period of collection, the balance of the Settlement would be further tilted against APS's stockholders.

*B. Shopping Credits*

**Q. Witness Kingerski expresses support for the "shopping credit" policies instituted by New Jersey and Pennsylvania and contrasts these states with California, which has experienced minimal consumer switching to new providers. (pp. 25-8) Has shopping in Pennsylvania been fairly uniform across all utilities?**

A. No. The shopping experience for Allegheny, generally conceded to be one of the lowest cost generators in Pennsylvania, is similar to that of California. The Allegheny experience is to be contrasted with the experience of GPU, one of the higher cost producers in Pennsylvania. For GPU the percentage of shopping is significantly greater than that in California. For example, the percent of industrial customers shopping is 76% compared to 33% in California.

**Q. Do you agree with his implied point that generous shopping credits are necessary to create effective competition?**

A. No. Shopping credits should reflect the marginal cost of provision of services. In lower marginal-cost states such as Arizona, large shopping credits will encourage inefficient entry by higher-cost producers, which will serve to raise rates for customers.

**Q. What are the other considerations that have a bearing on the issue?**

A. The length of the transition period should not be altered to produce a greater level of shopping. Larger shopping credits would require a longer transition period over which CTCs are collected. Lengthening the transition period has negative consequences: it delays the benefits associated with full competition and it increases the total cost of stranded cost recovery because of increases in capital costs. It also harms customers to raise current rates to create profitable entry conditions for less efficient firms.

New Jersey and Pennsylvania have both opted for long transition periods. For example, Pennsylvania's transition period varies from seven to ten years, compared with California's four-year transition period. One of the principal reasons that Pennsylvania and New Jersey opted for a long transition period was because both states have several utilities with very high levels of stranded costs. Attempting to recover these costs over a shorter transition period would have resulted in unacceptable rate increases. All else equal, large shopping credits depend on high bundled rates and long transition periods, neither of which is or should be the case with the APS agreement.

Furthermore, the size of the shopping credit and the resulting rate of shopping vary substantially with the level of a utility's initial rates. Since the shopping credit is determined by subtracting nongeneration-related charges (including CTC charges) from a utility's bundled rate, everything else equal, the greater the initial unbundled rate the higher the shopping credit. Consequently, states, such as Arizona, which have lower rate levels, would be expected to have lower shopping credits than states that have higher rates such as Pennsylvania and New Jersey. Making Arizona a higher-cost state so that higher-cost entrants can succeed is not a reasonable objective.

**Q. Are there utilities in other states that are expected to have relatively short transition periods and low shopping credits?**

A. Yes. According to a July 5, 1999 *Electricity Week Article*, Baltimore Gas and Electric (BG&E) recently signed a restructuring settlement that will allow it to recover its $528 million in stranded costs over four to six years. The article mentions that one of the reasons that BG&E's shopping credits are lower than those of Pennsylvania or New Jersey is that BG&E's rates are lower to begin with.

**Q. What conclusion do you draw from these data?**

A. These data indicate that shopping appears to be tied more heavily to utility costs and the desire to protect ratepayers from increased rates than to an attempt by a particular state to encourage uneconomic competitive entry.

*C. Credits for Other Services*

**Q. Witness Kingerski asserts that APS's proposed pricing structure for competitive services is inappropriate and can lead to customers being double charged. (p. 14) Do you agree?**

A. No. The approach proposed in the Settlement sets credits for services provided by ESPs that are appropriate because the credits:

- provide the proper price signal; and
- encourage efficient entry.

**Q. Please discuss what you mean by an appropriate price signal and discuss how the approach proposed in the Settlement is able to accomplish this objective.**

A. By appropriate price signal, I mean that credit should be set to maximize allocative efficiency. Allocative efficiency means that;society's scarce resources are allocated to their highest-valued use. This occurs when the price of a service (or the credit in the case of revenue cycle services) is set equal to its marginal (or short-term avoided) cost. Marginal (or short-term avoided) cost is the increase (or decrease) in cost that occurs when output is increased (or decreased) by a small amount. For the purpose of pricing credits for revenue cycle services, marginal or avoided cost is the net decrease in cost that occurs when there is a reduction in the level of the service provided. The net reduction should reflect both incumbent costs that are reduced and those that are increased (e.g., additional billing costs) if the service is provided by another supplier.

The efficiency reason that the metering and billing credits should be set equal to marginal or net avoided cost is that marginal cost is the economic cost that a customer's continued use of the service imposes on the economy. Thus, if credits are set equal to marginal costs, the savings from ending existing service arrangements will be the same as the savings to society (in terms of the reductions in scarce resources that are consumed). It should be noted that California uses a decremental cost approach for its shopping credits.

If the price is not set equal to the marginal cost, inefficiencies are introduced. To see this, assume that the net cost the utility avoids for a particular revenue cycle service is $5, and the credit for the service is set at $8. Assume further than an ESP can provide the service for $6. In this situation, the ESP could charge the customer a price slightly below the credit, say $7. At this price the ESP will be able to attract the customer since the customer would save $1 (8-7), and the supplier could make a profit of $1 (7-6). However, the utility will lose $3 (8-5), which will have to be either added to the CTC or to Standard Offer rates. More of society's scarce resources will be used because a less efficient supplier will provide the service.

If instead the credit were set equal to the utility's net avoided cost, then consumers would not choose the higher-cost ESP to provide the service, since its marginal cost of providing the service exceeds the credit. Only those providers with a marginal cost of provision below that of the utility would be able to attract customers. Thus, setting the credit equal to marginal cost provides the proper price signal that the more efficient provider should serve the customer.

**Q. Please discuss how the approach used in the Settlement sends the correct price signal.**

A. According to the Settlement, credits are based on short-run avoided or decremental cost. As such, they reflect the costs that the utility is able to avoid or save when an ESP provides the competitive service. As previously discussed, use of marginal or avoided cost will maximize allocation efficiency, resulting in society's scarce resources being allocated to their highest-valued use.

**Q. How does the approach proposed in the Settlement prevent cross-subsidies and encourage efficient entry?**

A. Since the credit is set equal to the net cost the utility avoids when an ESP provides the service, the utility will receive the same contribution to the CTC and recovery of other costs, irrespective of who provides the service. From an efficiency standpoint, setting this credit equal to marginal or avoided cost provides the opportunity for the utility to recover its costs and ensures that the service will be provided by the competitor who can do so at lowest cost.

It should be noted that setting credits in excess of avoided cost would result in cross-subsidies from the utility to competitors. This occurs because the credit given to the ESP will exceed the cost that the utility saves. Since rates are fixed, the shortfall will have to be made up by the utility.

**Q. Do the credits prevent double counting?**

A. Yes. Customers receive a credit equal to the cost the utility avoids if the ESP provides the service. Hence, the customer is not being double charged since the credit for the decremental costs of the utility is subtracted from the customer's distribution bill. Only costs that are not avoided are still paid by the customer.

**Q. Witness Kingerski assert that competitive entry cannot occur unless APS provides an embedded cost credit for ESP-provided services. (p. 20). What is your response?**

A. Entry is appropriate when it reduces the cost of supplying the service. The Commission's focus should be on providing an efficient competitive process, not on encouraging entry per se. The goal should be to set credits that correctly reflect actual marginal or avoided costs and let competitors enter when they can do so profitably.

Including costs that cannot be saved in the credit for competitive services will send an inappropriate price signal because the credits will exceed marginal or avoided cost and will result in inefficient entry. By obligating the incumbent to deliver a credit that is greater than the marginal cost of service--the true savings realized by the incumbent not having to provide the service--the utility would be forced to create an undue incentive for customers to switch providers from incumbent to entrants. This would lead to uneconomic bypass by inefficient competitors, and ratepayers may be adversely affected by resulting increases in the CTC, Standard Offer rates, or length of time required to recover stranded costs.

## III. TRANSFER OF APS ASSETS FROM REGULATED UTILITY TO AFFILIATE

### *A. Transfer of Assets at Book vs. Market Value*

**Q. Witnesses Oglesby (p. 5), Rosenberg (p. 4), and Delaney (p. 3) argue that the provisions in the Agreement for the transfer of the Company's generation assets will understate the value of the assets. Do you agree?**

A. No. The Agreement provides for the transfer of the Company's generation assets at book value. As I stated in my direct testimony (p. 10), I believe that the book value of APS's generation portfolio will be greater than the market value of the assets at the time of the transfer. I believe this for two reasons. First, the

Company has used very conservative assumptions in the estimation of stranded costs. It is very likely that the Company's stranded costs will be well in excess of the $533 million estimate that has been filed with the Commission. Second, as part of the Agreement the company has limited its recovery of stranded costs to $350 million. For these two reasons, I think it is incorrect to assert that APS's generation assets will be undervalued at the time they are transferred to a subsidiary.

*B. Auctioning of Assets*

**Q. Both Dr. Rosenberg and Mr. Delaney (p. 6) suggest that APS auction its generation assets instead of transferring them to an affiliate. Do you agree with this recommendation?**

A. No. First, I understand that there is considerable debate as to whether or not the Commission has the authority to force the utility to divest its assets to a third party. Throughout this debate, the Commission has repeatedly decided not to order generation divestiture.

Notwithstanding the issue of the Commission's authority, auctioning would be a draconian way of determining the market value of generation assets. It would be like killing a fly with explosives. It can be effective, but is likely to cause greater harm. In my view, management, not the Commission, should decide whether to sell assets and, if so, how and when. In addition, forced auctions have other disadvantages. These include:

- For the most part, only physical assets (primarily generating stations) can be auctioned or sold. Other sources of stranded costs (such as regulatory assets or purchased power contracts) often cannot be valued in this way and will still require the use of another method.

- Conducting an auction can require considerable time and expense. Consequently, until the auction is completed, it will be necessary to use some other method to estimate the stranded costs of generating plants. Also, the cost of the auction will add to the magnitude of stranded costs.
- It will be very difficult, if not impossible, to establish the value of nuclear plants through an auction process. There are substantial restrictions on the transfer of ownership and operation of nuclear generation plants. Moreover, nuclear plants that have been sold have resulted in negative prices; the "seller" had to pay the buyer to accept the assets.
- The sale of plants creates substantial transaction costs, such as paying taxes, transferring complex or interdependent power supply contracts, soliciting shareholder approvals, and obtaining the release of indentured property from bondholders.
- If regulations force inefficient auction or one held at an inappropriate time, valuations of the assets may be distorted, thereby reducing the efficiency of this market-based mechanism.
- The competitive market may reveal that vertical integration of generation with transmission and distribution yields efficiencies that

benefit consumers. Forced divestiture would unnecessarily eliminate those benefits to the harm of both consumers and the utility.

## IV. CONCLUSIONS

**Q. Please summarize your conclusions.**

A. The Settlement Agreement serves the interests of ratepayers and shareholders and is fair to all potential competitors in Arizona. The Settlement introduces retail access for consumers, mandates explicit rate reductions, and partially compensates the utility for stranded costs. It will lay the foundation for fully competitive markets and the consumer benefits that go along with such markets. I believe that the intervenors' concerns discussed here are adequately addressed by the Settlement or by existing regulatory institutions. The Commission will serve the public interest by approving the Settlement.

**Q. Does this conclude your rebuttal testimony?**

A. Yes, it does.

BEFORE THE ARIZONA CORPORATION COMMISSION

| | |
|---|---|
| IN THE MATTER OF THE COMPETITION IN THE PROVISION OF ELECTRIC SERVICES THROUGHOUT THE STATE OF ARIZONA | DOCKET NO. RE-00000-C-94-0165<br>PROCEDURAL CONFERENCE |

At: Phoenix, Arizona

Date: February 5, 1998

Filed: FEB 09 1998

REPORTER'S TRANSCRIPT OF PROCEEDINGS

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Prepared for:

ARIZONA PUBLIC SERVICE
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CERTIFIED COPY
(When in red)

EXHIBIT
APS-15
Admitted

have prefiled summaries. Those are acceptable.

MR. WHEELER: Second question is I would like clarification from you and from RUCO regarding the extent to which you will treat the estimates of RUCO's witness Dr. Rosen on stranded costs for TEP and APS and Salt River Project. It was my understanding after talking with RUCO that they are being offered as illustrative examples of how a particular calculation methodology would work but that RUCO was not requesting that the Commission adopt any of those calculations as stranded cost estimates for any of the utilities in this proceeding and that you, likewise, understand that not to be within the scope of the proceeding.

HEARING OFFICER RUDIBAUGH: Actually, I was getting ready to make a summary judgment for RUCO and be done with it. But since you brought it up, RUCO, would you like to respond?

MS. SCOTT: Thank you, your Honor. That is correct. The figures and the model were made for the purpose of illustrating and supporting our methodology, and RUCO understands that if the utilities are allowed to recover stranded costs that there would be subsequent hearings on a utility-by-utility basis.

BEFORE THE ARIZONA CORPORATION COMMISSION

# REBUTTAL TESTIMONY

OF

WILLIAM H. HIERONYMUS

On Behalf of

Arizona Public Service Company

Docket No. RE-00000C-94-0165

February 4, 1998

Dr. Rosen's Estimate of Arizona Utilities' Stranded Costs

**Q. Have you reviewed RUCO witness Rosen's estimate of strandable costs?**

A. Yes, but only in a cursory fashion.

**Q. Why haven't you reviewed these estimates more fully?**

A. First, these estimates serve no useful purpose in this current proceeding. The Order establishing the proceeding does not invite an estimate of the magnitude of stranded costs. Even Dr. Rosen acknowledges that his estimate is "generic" and that utility-specific investigation would be required.

Second, Dr. Rosen's estimate is so badly flawed that no purpose is served by a detailed review. Because its flaws are so serious, it cannot even be used to determine the order of magnitude of stranded costs for Arizona utilities.

**Q. Based on the review that you have performed, can you indicate what are the largest flaws in Dr. Rosen's analysis?**

A. Yes. There are several major flaws. While I will refer to his estimate of APS's stranded cost in this discussion, these flaws are generic and apply to all three estimates.

First, he compares APS's generation costs to the retail prices that he projects in Arizona. APS will not serve the entire retail load in its historic service area, and APS generation will not serve *any* of it. By including the full retail margin of the retailers serving that load, but none of the retailing costs, in his calculation, he has vastly understated stranded costs.

Second, in determining the stranded cost of APS's generation, it clearly is not appropriate to attribute to it the profits earned by non-APS generators, nor to assume that APS potentially strandable generation can produce more output than is technically feasible, much less economic. Dr. Rosen asserts in a footnote to Exhibit __(RAR-4), Page 1, that he is multiplying stranded cost per kWh by system generation excluding purchased power. Yet by 2020, he assumes that generation will grow from 18 TWh to 30 TWh. (For SRP he assumes even greater growth from 19 TWh to 49 TWh.) In order to be included properly in the analysis, this *entire* output would have to be produced by APS's existing generating facilities. Yet the production capability of those facilities will not grow magically over the next 20 years. Rather, it will fall due to aging and retirements. It is the inflated profits on this purely phantom generation that are a major cause of his faulty conclusion that APS's generation will produce massive profits in later years.

Third, the base year estimate of APS's generation cost is grounded on a cost allocation that even Dr. Rosen characterizes as "a few simple allocation methods". He accepts that it would require refinement in order to be useful.

Fourth, he assumes that the price received by APS generation will reach full long run marginal cost, or "replacement" cost by the year 2000. This is wholly unreasonable. Again, by materially overstating APS generation revenues, he understates its stranded costs. As I described previously, the inability of replacement cost methods to determine prices in transition periods is a major drawback of such methods. While Dr. Rosen is supposedly using a net revenues lost method, he in fact assumes that market prices will reach replacement cost levels during all hours of the year by 2000. This is several years earlier than is likely to be the case

Fifth, his forecast of escalation in the regulated cost of generation – negative 3 percent in real terms through 2004 and negative 2 percent thereafter – is merely a guess and lacks any valid foundation.

Sixth, his forecast of escalation in the market price, plus 5 percent per year in real terms in the near term and slightly positive in real terms in the next century, similarly lacks any valid basis. Likely errors include the assumption that market prices will reach full replacement cost by 2000, discussed above, and the assumption that there will be no technological change that reduces generating cost in real terms over the 25 year period of his study.

Seventh, stranded regulatory assets seem to have fallen entirely through the cracks of his study.

Q. **One of your criticisms, number 4, was that his assumption that market prices will reach replacement cost levels by 2000 is in error. Please explain why this is an error.**

A. In general, the wholesale price of power in the western US is a net-back price from southern California. While delivered prices differ across the area due to line losses, transmission charges and the effects of transmission constraints, the generation price itself is set over this very large area.

The WSCC has very substantial excess capacity, even relative to historic reserve margin requirements. The fact that APS itself does not have excess capacity is entirely irrelevant to the impact of this regional excess capacity on market prices. Moreover, most observers believe that these historic, administratively set, reserve margins are higher than those that a competitive market will support. This is particularly the case in California, where there now is no installed reserve requirement whatsoever. Mr. Davis's testimony, which is based on a 12 percent reserve for the WSCC, projects excess capacity until 2006. There is certainly no reason to believe market prices will reach replacement cost prior to that date.

Excess capacity reduces what customers will pay for capacity. A surplus energy with low variable costs also reduces the value of energy. In today's WSCC market, in times of high water flow (for hydro), coal generation and even nuclear generation is shut in because the market clearing energy price is below even their low variable costs. This disequilibrium in energy markets may persist even after capacity is needed.

**Q. Dr. Rosen at page 45 cites an EIA study as demonstrating that by 2000 incremental load will be based on a replacement mix of combined cycle and combustion turbine plants. Please comment.**

A. This appears to be a purely theoretical study. Indeed, Dr. Rosen cites that it assumes *unplanned* generation additions starting in 1996, then projects a small number of other additions. The total additions cited, less than 3000 MW, are a miniscule fraction of total WSCC generation. Dr. Rosen leverages this tiny amount of plant (for which no substantial basis exists) to assume that all kWh in the WSCC will be priced at replacement cost.

There probably will be new generating plant built in the WSCC in the fairly near future, despite excess capacity. I am aware of two projects that have been proposed, though neither is under construction. However, both are in transmission constrained areas (the San Diego Basin and Southern Nevada). Capacity and energy are more valuable in these areas than elsewhere, precisely because the areas are constrained. Even if prices in constrained areas rise high enough to justify building new plant – and there is as yet no evidence that they will – this does not mean that prices in the unconstrained areas of the WSCC will rise to those same levels.

**Q. What do you conclude based on this review of Dr. Rosen's estimates of the stranded cost of Arizona utilities?**

A. His estimates of stranded cost are strongly biased downward and are wholly unreliable. His conclusions do not inform the debate over generic policy issues that are the proper subject of this proceeding, and Dr. Rosen's estimates should be completely discounted.

**Q. Does this compete your rebuttal testimony?**

A. Yes.

APS Standard Offer Service Charges

(These are charges for services that are also available from competitive generation suppliers.)

Generation

Charge for kWh used

Charge for kWh Demand

Transmission and Ancillary Services associated with Generation

Metering

Meter Reading

Billing

APS Noncompetitive Charges

(These charges will apply whether you have a competitive generation supplier or not.)

Distribution Service

Transmission and Ancillary Services associated with Distribution

Regulatory Charges and Taxes

(These apply whether you have a competitive generation supplier or not.)

System Benefits Charges

Competition Transition Charges

Regulatory Assessment

Sales Tax

How Good Is the APS Generation Shopping Credit?

July 15, 1999

| Customer Class | Standard Offer | Regulated Tariffs for Competitive Customers | Transmission and Ancillary Services | Estimated Shopping Credit* |
|---|---|---|---|---|
| Residential | $0.097760 | $0.062030 | $0.00514 | $0.03059 |
| Small Business Customer (under 3 Mw)[1] | $0.097215 | $0.046613 | $0.00476 | $0.04584 |
| Large Business Customer (3 Mw and more) | $0.054373 | $0.023848 | $0.00320 | $0.02733 |

* Pure Electric Commodity, includes transmission line losses and load factor adjustments.

Source: Arizona Public Service Company Response to Commonwealth Energy Corporation's First Set of Data Requests, ACC Dockets E-01345A-98-0473, E-01345A-97-0773, RE-00000C-94-0165, dated June 28, 1999.

**PV NYMEX Price** (July 1999 - June 2000): $0.032 at 50% load factor
$0.030 at 75% load factor

[1] Direct Access Meter Requirements, along with "Avoided Cost" Metering and Billing Credits, will displace any margin for Shopping Credit.

EXHIBIT
Commonwealth
5
Admitted