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E-00000A-01-0630
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E-01933A-98-0471

PART 1 OF 2
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To review Part 2 please see:

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APS

ORIGINAL

Jana Van Ness
Manager
State Regulation

Tel 602/250-2310
Fax 602/250-3399
e-mail:Jana.VanNess@aps.com
http://www.apsc.com

Mail Station 9905
P.O. Box 53999
Phoenix, AZ 85072-3999

Arizona Corporation Commission
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February 25, 2002

Docket Control
Arizona Corporation Commission
1200 W. Washington
Phoenix, Arizona 85007

RE: IN THE MATTER OF THE GENERIC PROCEEDINGS CONCERNING ELECTRIC RESTRUCTURING ISSUES
DOCKET NO.s E-00000A-02-0051, E-01345A-01-0822, E-00000A-01-0630
E-01933A-02-0069, E-01933A-98-0471

Dear Sir or Madam:

Pursuant to the Procedural Order Dated January 25, 2002, Interested Parties were offered the opportunity to respond to questions presented by Chairman Mundell, Commissioner Irvin and Commissioner Spitzer.

Attached, please find a consolidated response of Arizona Publics Service Company ("APS") addressing each of the Commissioners letters and questions as presented. Parties of record have been served with this response and provided a CD-ROM of the attachments in lieu of written documents.

If you or your staff have any questions, please feel free to call me.

Sincerely,

Jana Van Ness

Jana Van Ness
Manager
State Regulation

Attachment

JVN/srm

Cc: Docket Control (Original, plus 18 copies)
Mr. William Mundell, Chairman
Mr. Jim Irvin, Commissioner
Mr. Marc Spitzer, Commissioner
Mr. Christopher Kempley, Chief Legal Counsel, Legal Division
Mr. Ernest Johnson, Director Utilities Division
All Parties of Record

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ARIZONA PUBLIC SERVICE COMPANY'S RESPONSES TO COMMISSIONERS' QUESTIONS ON ELECTRIC POLICY ISSUES

Arizona Corporation Commission
Docket No. E-00000A-02-0051

February 25, 2002

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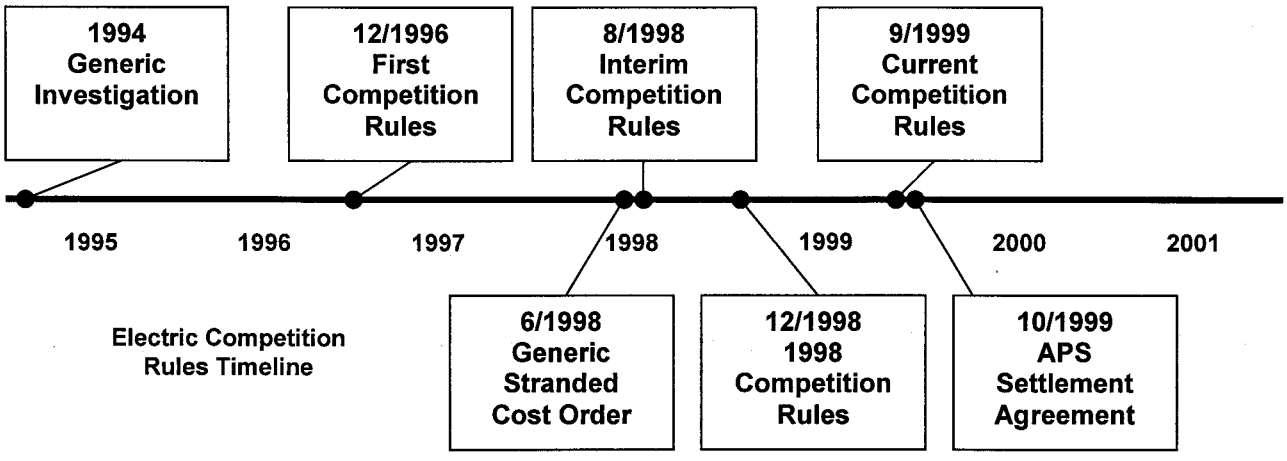
SECTION I
INTRODUCTION AND EXECUTIVE SUMMARY

1.1 Introduction

Arizona Public Service Company ("APS" or "Company") welcomes the opportunity to respond to the thoughtful and far-ranging questions posed by all three Commissioners on electric policy issues. In its consolidated response to these questions, the Company has organized the questions by author rather than by topic. Although this necessarily results in some overlap, it should make the responses easier to follow and allow the reader to better focus on a particular question or group of questions. An executive summary with the Company's recommendations, as well as appendices with supporting documentation, are included for the convenience of the reader.

Before reaching the substance of the Company's responses, some background on the Commission's restructuring efforts to date is appropriate. This background should serve as a reminder of how far the stakeholders have come to reach the present circumstances.

The Commission first opened an investigation on retail electric competition in 1994. By 1996, the Commission issued its first proposed electric competition rules. After numerous public meetings and volumes of written comments, these rules were adopted by the Commission in Decision No. 59943 (December 26, 1996). As originally enacted, these electric competition rules did not contain many of the provisions now claimed by some parties to be "cornerstones" of restructuring. For example, there was no required separation of competitive and non-competitive electric services, no code of conduct requirement, no competitive bidding or market acquisition requirements of any kind, and no divestiture. Under these first rules, retail open access was to begin in phases starting in 1999.



The 1996 electric competition rules were challenged by virtually all of the incumbent electric public service corporations, including the Company. However, no independent power producer ("IPP") or competitive retail electric service provider ("ESP") challenged these rules, despite the failure of these rules to address the issues mentioned above. The 1996 electric competition rules remained in place until 1998, when the Commission decided to reopen them.

In July of 1998, a new set of electric competition rules was proposed and later adopted on an interim basis in Decision No. 61071 (August 10, 1998). These new rules, which were finalized on a "permanent" basis late in the evening of December 31, 1998, added the mandatory divestiture requirement for the first time but still made no mention of competitive bidding for Standard Offer Service. They also did away with the Solar Portfolio Standard, which was the predecessor of the current Environmental Portfolio Standard. These electric competition rules lasted only six days before they were stayed by the Commission pending yet another rulemaking process.

It was this latter process that culminated in the present version of the Electric Competition Rules. First proposed in April 1999, these rules were adopted in Decision No. 61969 (September 29, 1999). As proposed, there still was no competitive bidding requirement for Standard Offer Service, but one was added—primarily at the urging of Enron and Commonwealth, which were two ESPs involved in the rulemaking—in the form of Rule 1606(B) during the Commission's Open Meeting deliberations on this latest version of the rules.

The end of 1998 also saw the first attempt to resolve a series of outstanding restructuring issues through negotiation and settlement. In November of that year, APS entered into a three-way settlement agreement with Commission Staff and Tucson Electric Power Company ("TEP"). APS would be permitted to retain its generation despite the new electric competition rules (and even acquire some of TEP's generation) but would divest most of its high voltage transmission system to TEP. Neither utility had to write-off any stranded costs.

The 1998 APS-TEP-Staff settlement was appealed to the courts even before the Commission could hear it, and it quickly died. The Commission asked APS and TEP to meet with affected customer groups and try to negotiate new settlement agreements having even more broad-based support. This was done, and on May 14, 1999, APS and all of its major consumer groups filed what is still referred to as the 1999 APS Settlement.

The 1999 APS Settlement called for numerous additional concessions from APS. Although the Commission in the 1998 electric competition rules—and also in the version of those rules then under consideration by the Commission—as well as in Decision No. 60977 (June 22, 1998)("Generic Stranded Costs Order"), had assured utilities of <u>full</u> stranded cost recovery, APS agreed to a $234 million write-off of stranded costs and to a series of five rate reductions for both Standard Offer and Direct Access customers of APS. APS also agreed, absent emergency circumstances, not to seek any rate increases prior to mid-2004 and to forego recovery of any increased purchased power costs incurred until after mid-2004. And, despite assurances in Decision No. 60977 that APS would receive full recovery of the significant costs of asset divestiture, APS agreed to give up a third of such recovery. Finally, APS agreed to a code of conduct even more restrictive than required under the current Electric Competition Rules. In return, Pinnacle West Capital Corporation ("PWCC"), but not APS, received a partial waiver of some of the Affiliate Rules (A.A.C. R14-2-801 to -806), and APS received the right to divest its generation assets to a newly created PWCC subsidiary, Pinnacle West Energy Corporation ("PWEC").

The 1999 APS Settlement was approved by Commission Decision No. 61973 (October 6, 1999). It later was upheld as lawful and binding by the Arizona Court of Appeals in actions brought both by Enron and the Arizona Consumers Council. During the pendency of this litigation, APS dutifully wrote-off $234 million of what the Commission had already determined to be prudently-incurred costs, and decreased its rates in 1999, 2000, and 2001 by some $119 million. It spent literally tens of millions of additional dollars to comply with the Electric Competition Rules, including the divestiture requirement. Tens of thousands of man-hours were also devoted to these tasks. To meet APS' growing electric load and to ensure reliability for APS Standard Offer customers, PWEC began construction of approximately 1,800 MW of new generation in the Phoenix area, some of which has already been completed and placed into service for the benefit of APS customers.[1] To obtain permanent financing for the over $1 billion in new PWEC investment, PWEC relied on the Commission's assurance that PWEC would receive the existing APS generation assets, with PWCC providing only temporary funding in the interim through a series of short-term bridge loans. And, despite the opportunity to sell the output in the lucrative California market, it was held back for future use by APS customers.

The California energy crisis during 2000 led APS to re-evaluate the wisdom of going to the volatile wholesale market for the quantities of power envisioned by Rule 1606(B). This was especially true when the winter of 2000-2001 did not suggest any end in sight to the instability that had begun the previous spring. Skyrocketing and volatile wholesale prices also made it impractical for ESPs to compete in Arizona against fixed or declining Standard Offer rates. The demise of retail competition in California and Nevada, and its delay in New Mexico, reduced Arizona to a "stand-alone" play for ESPs in the Desert Southwest, and many left the state or went out of business.

Faced with the need to secure large amounts of power at reasonable, stable and predictable prices in order to preserve Standard Offer Service as a safety net for customers unwilling or now potentially unable to take advantage of Direct Access, APS turned to an entity that had proven capable and willing to assure reliable supply for APS' Standard Offer customers—PWCC. Eventually, a long-term purchase power agreement was negotiated with PWCC whereby PWCC, using PWEC's assets, was able to offer APS a secure and diverse portfolio of power at essentially cost-of-service prices. This agreement necessitated that APS seek a partial variance to Rule 1606(B). In APS' view, the partial variance request is well within the intent of the Electric Competition Rules and is <u>not</u> a request to change the 1999 APS Settlement Agreement—an agreement that has already produced significant benefits for Arizona and should continue to be honored.

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[1] This capacity figure does not include temporary generation installed in the Summer of 2001 by PWEC at a cost of $30 million.

1.2 Executive Summary

Addressing the Commissioners' questions necessarily requires a lengthy response, and APS has attempted to respond to each question with enough detail to be informative and present the Company's position on issues raised by the question. However, the essential points in the Company's responses can be distilled to the following:

- The current Electric Competition Rules represent, on the whole, a balanced and workable framework for the introduction of retail electric competition and do not require drastic changes at the present time. However, the Electric Competition Rules do not address supply reliability, which is a critical component of the ability of Utility Distribution Companies ("UDCs") to provide service to their customers.

- That said, there are of course minor changes that would improve the regulatory treatment of the competitive retail market for the Company, its customers, and its competitors and that would remove uncertainty about the legality of the Electric Competition Rules.

- The Western wholesale electric market has proven to be very volatile and at the moment lacks long-term predictability regarding price, has insufficient price transparency, and imposes no responsibility for reliability. This wholesale market is subject to exclusive and extensive federal regulation and jurisdiction and thus the direct impact of the Commission on such markets is necessarily more limited than in the retail competitive marketplace.

- Properly designed Regional Transmission Organizations ("RTOs"), such as WestConnect RTO, L.L.C. ("WestConnect"), of sufficient scope or with effective seams policies will provide necessary additional structure and enhance the competitive generation market.

- The Commission should focus on the long-term development of the retail competitive market, and recognize that risk-free competitive choice is unrealistic. The consumer's right to choose carries with it the possibility of making a poor choice.

- APS' Request for a Partial Variance and the approval of the Purchase Power Agreement with PWCC, pending in Docket No. E-01345A-01-0822, represents a balanced and reasonable means of providing significant protection to Standard Offer customers, provides a needed transition period for wholesale market development, and does not affect customers' ability to select alternative competitive suppliers.

1.3 APS' Recommendations to the Commission

Although APS is aware that Staff will prepare a report based on the responses received from interested parties to this docket, APS nonetheless offers several recommendations to the Commission in proceeding forward with this investigation:

- Keep the existing framework for the Electric Competition Rules and make modifications to such Rules on the margin or through individual variance requests, as appropriate.

- Remedy the legal issues raised by Judge Campbell's ruling in the consolidated Electric Competition Rules litigation now pending in the Court of Appeals.

- Maintain reasonably-priced and reliable Standard Offer Service and the financial viability of those UDCs that provide such service.

- Provide strong regulatory support for the formation of RTOs, such as WestConnect, that recognize regional market differences, appropriately defer to state autonomy, and comply with the Federal Energy Regulatory Commission's ("FERC") requirements for RTOs.

- Establish regular panel presentations by industry participants on topics of interest and significance to the Commission's regulation of the electric utility industry, such as federal legislation (including facilities siting and federal tax initiatives), RTOs, and new technology.

- Clearly define the essential planning responsibilities of the provider of last resort for both transmission and generation resources.

- Conduct a rulemaking on facilities siting to review and properly codify permissible practices to increase the predictability and efficiency of such proceedings.

- Streamline and reduce transaction costs of all regulatory processes, but especially those that affect competitive services and competitive service providers.

- Coordinate regulatory efforts with the legislature regarding public power.

- Promptly approve APS' Request for a Partial Variance and approve the proposed PPA with PWCC.

SECTION II
CHAIRMAN MUNDELL'S JANUARY 14, 2002 LETTER

2.1 Identification of Competitive Products

A. ***What are the possible goods and services traditionally provided by the electric utility for which retail competition is possible? You may address the following categories of goods and services:***

(1) ***generation, including baseload, intermediate and peaking power; green power; distributed generation; firm and nonfirm power; long- and short-term contracts; backup and coordination services;***

(2) ***distribution services, including ownership, construction, maintenance and repair of the physical lines; metering ownership, installation, reading and data analysis; and the process of planning for and negotiating with distributed generators;***

(3) ***aggregation services, such as load profiling; load planning; customer services; data analysis; billing; generation planning; power supply acquisition; demand side management, energy efficiency and other services relating to matching supply and demand.***

Responses to these questions are provided in tabular format at Table 2.1A, below. Note that for many aggregation services for which retail competition is possible now, the ability of a consumer to actually choose the product may be limited. For example, while billing is a competitive service, the customer's ESP will in most cases dictate what billing provider is used and how billing and other competitive services are provided along with the commodity component.

Table 2.1A

PRODUCT OR SERVICE	ASSUMED DEFINITION	IS RETAIL COMPETITION POSSIBLE NOW?	IS RETAIL COMPETITION POSSIBLE IN THE FUTURE?
1. Generation			
Baseload, intermediate and peaking power	Baseload power is generated by units designed to serve load on an around-the-clock basis. Peaking power is generated by units designed to operate only during periods of highest daily, weekly or seasonal load. Intermediate power is generated by units designed to operate for periods longer than peaking units but shorter than baseload units.	Yes, collectively for small customers and individually for very large customers.	Yes, collectively for small customers and individually for very large customers.

PRODUCT OR SERVICE	ASSUMED DEFINITION	IS RETAIL COMPETITION POSSIBLE NOW?	IS RETAIL COMPETITION POSSIBLE IN THE FUTURE?
Green power	Power supplied from renewable energy sources.	Yes	Yes
Distributed generation	The use of small generation units (utility or end-user owned) at diverse locations on the distribution system.	Yes	Yes
Firm and non-firm power	Firm power is purchased under a contract that makes the capacity essentially available at all times; non-firm power is capacity that is not available at all times.	Yes for large customers; to a more limited extent for small customers.	Yes for large customers; to an increasing extent for small customers.
Long- and short-term contracts	Long-term contracts are purchase power contracts with a duration generally of a year or longer. Short-term contracts generally have a duration of up to one year.	Yes	Yes
Backup services	Power supply provided to replace the generation owned by an end-user when that generation is on a forced or scheduled outage.	Yes	Yes
Coordination services	Services provided by scheduling coordinators giving advanced notice to the system operator of the expected load level for the scheduler's clients.	Yes	Yes
2. Distribution Services			
Distribution lines	Ownership, construction, maintenance and repair of facilities to deliver power at distribution voltage levels.	No	No
Metering	Ownership, installation, reading and maintenance of end-user metering as well as the analysis of meter reading data.	Possible, but unlikely to be widespread under existing circumstances.	May be more prevalent in the future.
Planning for and negotiating with distributed generators	Self-explanatory	No, because distribution system planner must account for these installations in planning distribution wires system.	No, because distribution system planner must account for these installations in planning distribution wires system.
3. Aggregation Services (supplied to ESP, not end-user)			
Load profiling	The process of estimating a customer's hourly energy consumption based on measurements of similar customers.	No, but the use of load profiling facilitates retail access for small customers.	No, but the use of load profiling facilitates retail access for small customers.

PRODUCT OR SERVICE	ASSUMED DEFINITION	IS RETAIL COMPETITION POSSIBLE NOW?	IS RETAIL COMPETITION POSSIBLE IN THE FUTURE?
Load planning	Planning to meet load growth on the transmission or distribution systems.	No	No
Customer services	Customer account maintenance and call center for customer contact regarding account.	Yes	Yes
Data analysis	Analysis of consumption data to determine end-user usage patterns.	Yes	Yes
Billing	The process of creating a bill or invoice for end-user consumption.	Yes	Yes
Generation planning	Planning generation additions to meet end-user demand on the system.	No	No
Power supply acquisition	Negotiation for and procurement of power supply by an ESP to meet its aggregated, end-user demand.	Yes	Yes
Demand side management	The planning, implementation and monitoring of utility activities designed to encourage consumers to modify patterns of electricity usage, including the timing and level of electricity demand.	Yes	Yes
Energy efficiency	Programs that are aimed at reducing the energy used by specific end-use devices and systems, typically without affecting the services provided. These programs reduce overall electricity consumption, often without explicit consideration for the timing of program-induced savings. Such savings are generally achieved by substituting technically more advanced equipment to produce the same level of end-use services (e.g., lighting, heating, motor drive) with less electricity.	Yes	Yes
Other services relating to matching supply and demand	Uncertain reference; assume here that it refers to such things as ancillary services and must-run generation.	Ancillary services can be supplied competitively; must-run generation cannot.	Ancillary services can be supplied competitively; must-run generation cannot.

B. For each good or service for which competition is possible, what are the possible benefits of competition for each good and service?

1. What are the potential price benefits?

2. Do the potential price benefits differ in the short-term and long-term?

Responses to these questions are provided in tabular format in Table 2.1B, below.

Table 2.1B

PRODUCT OR SERVICE	WHAT ARE THE POTENTIAL PRICE BENEFITS?	DO THE POTENTIAL PRICE BENEFITS DIFFER IN THE SHORT-TERM AND LONG-TERM?
1. Generation		
Baseload, intermediate and peaking power	Competition may drive prices to a level equal to the marginal cost of the marginal provider but may also introduce price volatility, at least in the short run.	These benefits may grow over time as new, more efficient entrants enter the marketplace and new methods are employed in operating existing units.
Green power	Minor or negative initially but there may be benefits as technologies mature and become more price-competitive with traditional power sources.	Prices for green power may decrease over time as a result of competition and technological advances.
Distributed generation	Over time, the use of distributed generation may eliminate some generation, transmission and distribution losses and the need for some transmission and/or distribution plant investment and expenses.	Should depend on circumstances.
Firm and non-firm power	Some end-users will be able to use non-firm power, which the market should make available at a lower price than firm power. In addition, some end-users could be able to sign firm contracts for an extended period of time at prices lower than those that prevail in a series of shorter term contracts. This should lead to greater use of demand-side resources for example, for reserve requirements.	Not for the large industrial customers who already have non-firm service available. Yes for other customers but the market must mature in this area. Market participants can be expected to develop new packages of firm and non-firm power for these customers.

PRODUCT OR SERVICE	WHAT ARE THE POTENTIAL PRICE BENEFITS?	DO THE POTENTIAL PRICE BENEFITS DIFFER IN THE SHORT-TERM AND LONG-TERM?
Long- and short-term contracts	At any given time, short-term contract prices may be equal to, greater than or less than those available in long-term contracts. This reflects the assignment of risk as between the buyer and seller. End-users should benefit from being able to choose the type of contract depending upon the level of price risk they wish to assume.	Price benefits should increase over time as the market matures and price differentiation between specific contract lengths progresses.
Backup services	Prices for the provision of this service could be market-determined and better reflect the cost to society of providing the service. Note that consumers may, in some cases, choose to self supply backup services.	Prices for these services should decrease over time as existing providers gain experience and new providers enter the market.
Coordination services	Competition should drive prices to a level equal to the marginal cost of the marginal provider.	Prices for these services should decrease over time as existing providers gain experience and new providers and new technologies enter the market.
2. Distribution Services		
Distribution lines	Not competitive.	Not competitive.
Metering	The market should bring forth cost-effective new technologies for measuring end-user consumption, although transition costs will be required. In addition, the time-differentiated cost of the provision of electric service will ultimately require time-differentiated metering and more rational pricing.	Yes. Because of the large installed base of traditional watt-hour meters, benefits will develop over time.
Planning for and negotiating with distributed generators	Not competitive.	Not competitive.
3. Aggregation Services		
Load profiling	Not competitive.	Not competitive.
Load planning	Not competitive.	Not competitive.
Customer services	New providers may enter the market (credit card companies, telecom-munications companies, others) bringing economies of scale and scope to bear.	Yes, most of the price benefits should occur in the longer term after scale and scope economies have been reached.
Data analysis	Better information regarding usage patterns should lead to more rational pricing for those customers not taking service on a time-differentiated basis.	Yes, most of the price benefits should occur in the longer term after providers of the service have more experience in predicting usage patterns.

PRODUCT OR SERVICE	WHAT ARE THE POTENTIAL PRICE BENEFITS?	DO THE POTENTIAL PRICE BENEFITS DIFFER IN THE SHORT-TERM AND LONG-TERM?
Billing	New providers may enter the market (credit card companies, telecommunications companies, others) bringing economies of scale and scope to bear.	Yes, most of the price benefits should occur in the longer term after scale and scope economies have been reached.
Generation planning	Not competitive.	Not competitive.
Power supply acquisition	Competition can be expected to weed out inefficient ESP negotiators resulting in lower prices to end-users.	Most of the price benefits should occur in the longer term after inefficient ESPs have been removed from the marketplace.
Demand side management	Off-peak usage should be rewarded with lower prices that reflect marginal cost. This should also put upward pressure on on-peak prices to reflect marginal cost. Pricing should better reflect cost in the longer term and lead to more efficient use of electricity. Reduced overall demand levels should lead to lower investment in generation.	While there may be short-term price benefits to some consumers (and costs to others), long-term benefits should be greater as demand responds to market price signals.
Energy efficiency	Given an adequate number of competitors, competition between them should drive prices for these programs to a level equal to the marginal cost of the marginal provider. Competition should force providers to operate in the most efficient manner possible. In combination, these two factors should yield lower prices for the programs and increased energy savings for consumers.	Benefits will probably be greater in the long-term as consumers respond to price signals and the market develops more energy-saving programs.
Other services relating to matching supply and demand	As new generation is built, a competitive market for ancillary services should develop.	Benefits will probably be greater in the long term as the competitive market develops.

3. What are the potential non-price benefits?

Please see Table 2.1C, below.

4. Are there any other potential benefits (e.g., environmental, energy security, etc.)?

Please see Table 2.1C, below.

Table 2.1C

PRODUCT OR SERVICE	WHAT ARE THE POTENTIAL NON-PRICE BENEFITS?	ARE THERE ANY OTHER POTENTIAL BENEFITS (E.G., ENVIRONMENTAL, ENERGY SECURITY, ETC.)?
1. Generation		
Baseload, intermediate and peaking power	Diversity of suppliers, but may or may not have the opposite effect on diversity of technology and geographical diversity.	Energy security may increase if supply diversifies geographically and technologically. New types of products and technologies may be introduced which may offer, among other things, environmental benefits and increased efficiencies.
Green power	Reduction in reliance on conventional generation. Diversity of supply sources.	Reduction of air emissions, water consumption and waste disposal issues associated with non-renewable generation. In addition, energy security may increase as supply diversifies geographically and technologically.
Distributed generation	Increased levels of customer satisfaction and security of supply or power quality.	Environmental effects could be positive or negative, depending upon the relationship between the comparative pollution levels and locations of distributed generation and central station units. However, environmental concerns are likely to be addressed in permitting processes. Energy security may increase as supply diversifies geographically and technologically, but there may be increased reliability concerns associated with interconnecting distributed generation.
Firm and non-firm power	Customer satisfaction will increase overall as risk preferences are more nearly matched to product offerings. More efficient use of generation units should also result.	Firm contracts for extended periods represent secure energy supply. Provides the opportunity to introduce demand side resources as well as supply-side resources to the market equation.
Long- and short-term contracts	Increase in consumer welfare from more nearly matching risk preferences to service options. Increased customer satisfaction and market efficiency.	A more diversified portfolio of product offerings may lead to new opportunities to create value.
Backup services	Elimination of possible subsidization of this service by other customers. Customer services for special reliability requirements.	Improved efficiency in customers' selection of self-generation, power supply and backup services, and pressure to increase the pace of technological advances.
Coordination services	Better matching of demand with supply options.	

PRODUCT OR SERVICE	WHAT ARE THE POTENTIAL NON-PRICE BENEFITS?	ARE THERE ANY OTHER POTENTIAL BENEFITS (E.G., ENVIRONMENTAL, ENERGY SECURITY, ETC.)?
2. Distribution Services		
Distribution lines	Not competitive.	Not competitive.
Metering	Opportunities for bundling product offerings and accelerated introduction of new techniques and technologies for measuring consumption and for monitoring equipment operation and demand management.	Opportunities to integrate energy management services with metering technologies will be accelerated.
Planning for and negotiating with distributed generators	Not competitive.	Not competitive.
3. Aggregation Services		
Load profiling	Not competitive.	Not competitive.
Load planning	Not competitive.	Not competitive.
Customer services	Non-traditional sources will bring new technology to the provision of this service.	Provide new opportunities for product bundling.
Data analysis		
Billing	Non-traditional sources will bring new technology to the provision of these services.	Unknown.
Generation planning	Not competitive.	Not competitive.
Power supply acquisition		
Demand side management	More opportunities for customer preferences to match with product offerings. Fewer power plants and transmission lines constructed because of reduced peak demand.	Better DSM product offerings, better match to consumer preferences. Likely to lead to lower power plant emissions (fewer plants).
Energy efficiency	Increased customer satisfaction.	Likely to lead to lower power plant emissions.
Other services relating to matching supply and demand		

2.2 Determination of Feasibility of Competition

A. Are the product and geographic markets for the good or service conducive to effective competition or manipulation by a single entity? For example—

1. Are there economies of scale which make it most efficient for the service to be provided by a single company?

There are scale economies when increasing inputs leads to a greater than proportional increase in output. Alternatively, scale economies exist if additional output produces lower per-unit costs. For example, scale economies may arise when a relatively fixed cost

in the production process gets spread over more and more units as output increases. In such cases, each additional unit produced lowers the average cost for all units.

In some circumstances, a monopoly can be the most economically efficient way to structure a particular market. A natural monopoly exists when it is cheaper for one firm to produce any quantity of a good than it would be for two (smaller) firms to produce that same quantity of the good. Firms and processes can display scale economies without demonstrating natural monopoly characteristics.

There are a number of processes that display natural monopoly characteristics. For example, the transmission function involves building and maintaining physical wires from generators to load centers. While it may be physically possible to run two sets of wires from each unit to each load center, it is generally inefficient to do so. System operation or control area operation also demonstrates natural monopoly characteristics. For the overall electricity system to be stable, it is necessary to keep supply and demand in tight balance on a moment-to-moment basis. This must be done by one entity rather than relying on individual generators or suppliers to take care of the balance themselves. This is one reason why a strong system operator is necessary.

The following discussion addresses the scale economies and monopoly characteristics of the products and services enumerated in the response to Question 2.1A. Some of the products and services are likely to display significant scale economies, while other services are likely only to display constant returns to scale—that is, increases in output that are proportional to increases in inputs. Still other functions in the industry demonstrate natural monopoly characteristics.

Generation services as a whole are not likely to have significant scale economies. While a single generating plant may show some scale economies, a firm with a number of plants, or a geographic market area is likely to have a much flatter cost curve and likely will demonstrate constant returns to scale.

- The degree of scale economy may vary across the type of generation service—baseload, cycling, and peaking—but it is unlikely to be significant at the market level. Because peaking units are in demand less often and at uncertain times, they may be able to demand a premium when there is a supply shortage, but there is no cost characteristic that would lead to scale economies.

- Since it is unlikely that there would be significant scale economies in generation, there should be no scale economies of production based on the length or firmness of contracts offered by firms who are providing generation. There may be price benefits from longer and firmer agreements.

- The market for providing distributed generation equipment is a national market. Consequently, the market for this equipment is likely to display constant returns-

to-scale. Distributed generation is likely to be uneconomic for very small sized applications. However, larger electricity users may find it economic.

- Because green power may involve some non-conventional technologies, such as geothermal, wind or solar power, there may be acquired knowledge or experience that reduces costs as output increases. There may also be scale economies due to economies of interconnection. For example, it is cheaper for a wind farm of 50 turbines to have a single interconnection to the grid than to have separate interconnections for each individual wind turbine. In general, competition between firms is likely to reduce costs more than costs could be lowered from a consolidation of all such generators into a single firm.

Distribution services include building, operating and maintaining distribution lines from the transmission grid to retail customers' sites.

- Supply of wire-related distribution services in a geographic market is likely to display significant scale economies with customer density, and to demonstrate natural monopoly features. It would be duplicative to have more than one firm set up a distribution system. In virtually all individual geographic markets, the savings from one company supplying wires-related distribution services will be so significant that competition should not be considered.

- End-use meter ownership, maintenance and meter reading are also part of distribution services. There are some scale economies from reading meters if individuals are sent out to do so. That is, if one person reads each meter, having meters that are close together means each read takes less time and thus costs less. However, new technology that reads meters more remotely is likely to benefit less from customer density.

Given the existing stock of interval meters that would have to be replaced, it is not likely that the adoption of new metering technology will be quick. Load profiling using existing meters will allow for competition to get started for residential and small commercial customers. New meters can be introduced as old meters wear out or customers see a benefit from moving off of their load profile.

Metering also involves data analysis of the meters read. Because metering companies will likely analyze data centrally using common resources, this function will show some scale economies. However, competition between firms providing metering services may produce significant savings over any lost scale economies from having more than one firm provide the service.

Aggregation services cover a range of services necessary to support aggregating loads for competitive retail service. These include customer services, data analysis, billing, power supply acquisition, demand side management ("DSM") and energy efficiency. The nature of the costs of providing these services varies across the services.

Some of these services, such as power supply acquisition and customer demand services (DSM and energy efficiency) are likely to show constant returns to scale. The nature of the other services is a bit more complex.

Customer services, data analysis and billing all require that a relatively large fixed cost (such as computer hardware, software, and call centers) be incurred before the service can be provided to any customer. However, once the fixed costs have been incurred, it is much cheaper (per unit of service) to add more customers since doing so only involves the relatively low variable costs of providing service to the customer. Significantly, the costs of these services, for the most part, vary with the number of customers and not with the quantity consumed by the customers. For example, it costs more to send out two bills for 10 MWh each than it does to send out one bill for 20 MWh. Consequently, the nature of the scale economies for these services are less related to the quantity of power provided and more to the number of customers served.

The degree of the scale economy depends on the relative sizes of the fixed cost incurred to provide the service and the variable cost of providing service to one more customer. While the relative sizes of the fixed and variable costs may be significant, it is not likely that the fixed costs will be large enough in the long term to act as a barrier to entry for firms wishing to enter the market.

2. Are there economies of scope which make it most efficient for the service to be provided in a bundle with certain other services?

Scope economies exist when it is cheaper to produce two products together than it is to produce them separately. Co-generation is an example of a scope economy. Often, it is cheaper to produce steam both for the industrial process and for electricity generation than it is to produce steam for one process alone.

This discussion addresses scope economies and monopoly characteristics of the products and services set forth in the response to Question 2.1A. Regarding the three general types of services: generation, distribution (lines and metering) and aggregation services, there are likely to be scope economies within these services, but scope economies between these services are less likely to be significant. The discussion below treats the scope economies within each type of service and then scope economies between the types of service.

Generation services described above included baseload, intermediate and peaking power, firm and non-firm power, long- and short-term power, backup and coordination services. There are likely to be some scope economies between generation services.

- For example, it may be possible to have different types of units (peaking, intermediate and baseload) at the same generating plant. The units could share costs that are common to all three types such as fuel handling equipment, administrative costs, and transmission and interconnection facilities. It is also

possible for the same unit to provide multiple services. In this manner, there are scope economies from producing different types of energy such as baseload and peaking energy. However, it is unlikely that these scope economies are significant enough to hinder the development of competition between a number of firms in Arizona providing these generation services.

Distribution services may also have some scope economies, such as between distribution lines and metering. While both of these services have been described as distribution services above, there could be cost savings between the distribution and meter installation and maintenance. The same maintenance crews could be performing each of these functions thereby reducing the cost of these services.

Aggregation services may similarly demonstrate some scope economies. These services include billing, data analysis and customer services. Because each of these services requires computing facilities and access to the same data, an aggregator may find it cheaper for a single entity to perform all of these functions than to have them performed by separated specialized firms. Standardized data formats may make it easier and cheaper for customer information to be used by multiple firms. However, these scope economies are not likely to be significant enough to hinder the development of competition between a number of firms offering aggregation services in the long term.

Between the types of service, scope economies are much less likely; there are not likely to be significant economies of scope between generation services and the distribution or aggregation services. The scope of wholesale energy markets limits the potential for cost complementarity—in which the marginal cost of producing one product declines as more of another product is produced—between these services. Similarly, there is not likely to be significant economies of scope between the distribution lines and aggregation services.

There may be, however, some scope economies between metering and aggregation services. The metering function includes the collection and analysis of metering data. Similarly, aggregation services include data analysis using customers' metered consumption data. It is likely a single entity could perform these functions more cheaply than multiple firms. Thus, there are scope economies between metering and the analysis of the data. Although there may be some economies of scope, it is not likely that they would be significant enough to hinder the development of competition among firms in the long term.

Therefore, in general, while there may be scope economies between some of these services, they are unlikely to be significant enough to overcome increased efficiency that competition in these functions will produce in the long term.

B. Are or will there be a sufficient number of competitors in each potentially competitive market?

1. Is the product or service one which viable competitors will actually be interested in providing?

The three types of services (generation, distribution and aggregation) and specific products within each type of service were described above. Although the particular details of implementation for each product and service differ, other states have introduced retail access for competitive services and have encouraged a number of providers to compete. In some states, not all the individual competitive services described above have been open to competition, yet firms have aggregated many of the separate services into bundles. It is likely the same type of service bundling will take place in Arizona, and many firms may not offer each of the separate services separately.

Nonetheless, there is a degree of competition among the bundled services in other states, although mostly for large customers who are more likely to choose direct access. For example, Illinois, which began to phase in retail access for residential consumers in October 2000, has 18 certified providers. Similarly, Texas began retail access in the middle of 2001, and it has 10 certified suppliers for residential consumers and 21 certified providers for commercial and industrial customers.

Of course, over the short term the decision of any single retail supplier to enter the market will be based on a variety of factors. If the price for commodity service from the incumbent is relatively low or the wholesale power price is relatively high, it may be more difficult for providers to enter the market to offer either pure commodity service or to attract customers to retail access by bundling other services or opportunities. Also, the relative size of the overall market and the relative location of the market may affect the decision of a competitor to devote resources to the market. Thus, for example, some firms may find the larger and more discrete Texas/ERCOT market a preferable current investment site to the smaller Arizona market. Such short-term effects, however, should not impact the long-term prospects for competition.

2. Is the cost of aggregating customers sufficiently small, relative to likely revenues, that new suppliers will find it profitable to enter?

See the response to Question 2.2 B(1) above.

3. Are there technical, legal, or other barriers to entry in the markets. For example:

(a) Are there legal or technical barriers to the construction of the different types of generation plants by non-utilities?

The Electric Competition Rules prohibit incumbent utilities from constructing new central station generation outside of a "non-utility" affiliate. That said, there are no

significant legal or technical differences inherent between different types of generation plants or that would prevent non-utilities from constructing such plants. The state's Siting Act, A.R.S § 40-360 *et seq.,* applies to all entities proposing to construct generation over 100 MW in Arizona (except on Tribal lands and for federal power marketing administrations).

With respect to specific types of generation, no new nuclear power plants are under development in the United States, but several merchant generating companies have announced interest in exploring pebble bed-type reactors which are under development in South Africa. Likewise, in other states both utilities and non-utilities are pursuing new coal-fired generation projects. At least one such project is planned in Arizona by an affiliate of TEP and Salt River Project ("SRP"). But the majority of the new capacity under construction in Arizona is natural gas-fired, where there are no particular technical or legal barriers specific to non-utilities. Finally, hydroelectric and renewable technologies (wind, geothermal, solar, biomass, and landfill gas) could be pursued by non-utilities without legal or technical barriers that are specific to such non-utilities.

Although there are no inherent legal differences between utilities and non-utilities regarding the siting of new generation, capacity over 100 MW does require approval under the Siting Act. The inability to obtain a Certificate of Environmental Compatibility ("CEC") would constitute a legal barrier to constructing new capacity in Arizona. Also, some may assert that including environmental-related conditions in CECs that go beyond the requirements of agencies with primary jurisdiction over such issues, such as the Environmental Protection Agency ("EPA), the Arizona Department of Environmental Quality ("ADEQ"), the counties, and the Department of Water Resources ("DWR"), could be construed as legal barriers to constructing new plants. APS, however, does not believe that the Commission's plant-siting actions are specifically related to the nature of the project proponents as utilities or non-utilities.

(b) Is the cost of obtaining licenses, resources, knowledge and employees sufficiently small, relative to the expected revenues, such that new entrants will find the market attractive?

For the most part, licensing, knowledge and employee costs for new entrants in Arizona are the same or roughly similar to those elsewhere in the United States. New power plants are increasingly being constructed by national firms, using turn-key engineering, procurement and construction agreements, and involve established and often modular technologies. Resource costs may be different than in some places in the United States. For example, there may be increased costs for water rights in Arizona due to the perceived scarcity of water and corresponding difficulties in obtaining water rights. Also, in some locations there may be difficulties in attracting necessary labor to construct projects. On balance, however, costs are likely roughly equivalent to other states in the Western United States.

Also, such costs are typically evaluated and justified on a project-by-project basis. Accordingly, whether such costs are small relative to expected revenues for individual

plants depends on the economics of the individual plant. For example, if a power plant elects to locate in an area with little existing transmission or natural gas infrastructure, the capital outlay of constructing new transmission or gas pipelines to interconnect the plant may significantly outweigh licensing or resources costs. The cost of pollution control and remediation is also a project-specific analysis.

C. Is it necessary for the product or service to be provided by a single regulated company to assure reliability and safety, or can multiple companies provide the service subject to reliability and safety rules?

In general, increased fragmentation involving products or services can affect reliability and safety in providing a given service. Indeed, one significant weakness of the Electric Competition Rules is that there is no party that is made responsible for reliability of supply to retail customers, a factor that prompted APS' Request for a Partial Variance. However, some services that lend themselves to competitive suppliers and for which adequate rules or contractual requirements are in place can be reliably and safely provided by multiple companies.

For generation, there are operating requirements and interconnection standards within APS' service territory so that generation can be supplied by multiple companies with manageable reliability and safety risks. However, the extent of control over reliability (both operationally and in system planning) in a restructured electric industry is necessarily less than when a vertically-integrated utility coordinated generation planning and operation with its overall system requirements and was accountable for adequate system planning and performance. Moreover, the use by competitive generators of a transmission system that was planned and designed to serve a vertically-integrated utility model dedicated to serving native load within defined service territories may result in the grid operating at or near its limits for longer periods of time, which would increase reliability risk. A load serving entity must also take resource diversity and geographic diversity into consideration in obtaining reliable service.

Grid-connected distributed generation has posed legitimate safety concerns. For example, personnel from the regulated utility need to be able to safely isolate sections of the grid to perform maintenance and repairs. If a non-utility owned distributed resource is interconnected to the isolated portion of the grid, it could cause a safety hazard without appropriate operating rules and system controls. However, properly-developed and implemented interconnection rules can address the majority of these concerns. From a reliability standpoint, grid-connected distributed generation generally requires the control area or distribution utility to provide adequate reserves for the load being served, minimizing the overall system reliability benefits of these resources.[2] This is not to say that distributed generation cannot contribute to local reliability by reducing load on local distribution facilities, including distribution substations.

[2] This is especially true if the distributed generation resource has a relatively low availability.

Although generation (both distributed and central station) from multiple entities can be interconnected and used reliably—subject to appropriate contractual and operational requirements—many related functions can only be provided by a single, accountable entity. Specifically, control area operations and system control can only be provided by a single entity to ensure that the grid operates correctly. Likewise, system planning and design should be performed by a single accountable entity, although certain sub-functions of these processes could probably be outsourced. Given the desire for accountability, such outsourcing should be discretionary. Distribution service also must be provided by a single regulated company, given the complex control and planning requirements associated with this service.

Some distribution-related services such as metering and meter reading can be provided by multiple companies, if adequate safety rules and standards to ensure technological compatibility are adopted. Standardization will also enhance the ability of customers to transfer between providers.

Apart from system planning functions, and load and resource matching, aggregation services generally do not pose reliability or safety concerns. For example, energy efficiency and demand side management usually occur on the customer side of the meter so they do not in and of themselves trigger reliability or safety concerns for a distribution utility. Similarly, competitive billing may pose commercial challenges but should not affect system reliability. One notable exception is load profiling, in which an electric utility determines a customer's typical load profile based on studies and analysis, rather than installing an interval meter for such customer. Because load profiles have implications for system planning and operation, load profiling for these purposes should be performed only by a single, regulated entity.

FERC's move toward larger RTO organizations carries with it some specific dictates about what functions must belong to the RTO entity. The RTO must be independent of all market participants with authority to propose the rates, terms and conditions of transmission service over its facilities. The RTO must also have operational authority over the transmission facilities under its control and exclusive authority for short-term reliability of the grid that it operates.

WestConnect will meet these criteria through an independent board overseeing the RTO's operations. WestConnect and transmission providers will also work cooperatively in a division of labor to ensure reliability and safety of the transmission systems. For example, while WestConnect will assume control area responsibilities for transmission facilities under its control, the participating transmission owners will physically execute operations under WestConnect's direction. WestConnect will also handle scheduling and have exclusive authority for determining interchange schedules, ordering re-dispatch for emergency operations or for must-run conditions and approving scheduled outages of transmission facilities and must run generators. WestConnect will essentially become the accountable entity, on a larger scale, like the transmission providers currently operating their systems in conjunction with each other today. Yet transmission providers will be

active participants in operating the systems for which they hold accountability to their native load customers and state commissions.

D. For customers, is the cost associated with learning how to shop and actually shopping sufficiently small, relative to the expected benefit, that customers will want to shop?

The answer to this question largely depends on the individual customer. It is more likely that larger commercial and industrial customers could conclude that the costs associated with shopping are outweighed by the benefits for several reasons. First, these customers may have a relatively large generation component to their overall electric profile. Accordingly, the direct benefit of lower or more flexible generation service is more likely to be significant for such customers. Second, these customers are more likely to be approached by ESPs with offerings to bundle energy efficiency programs or other services, which could reduce the net cost to such a company to invest the time and resources into shopping. Third, the transaction costs (including internal costs) on a per-kWh basis for large commercial or industrial customers would necessarily be less than for a typical residential customer. Finally, because electricity bills for smaller customers have been declining for Arizona customers (over 12 percent in the case of APS customers since 1994), it is less likely in the short term that smaller customers will be willing to invest significant time or resources into learning how to shop or shopping for what may be a relatively small savings to such a customer.

2.3 Relationship of Current Regulatory Regime to Competition

A. For each potentially competitive product or service, how does current state and federal regulation foster or inhibit (a) retail competition and (b) wholesale competition?

Congress and federal and state regulators have undoubtedly shaped the development of competition in wholesale and retail markets for electricity generation and delivery. Federal legislation and regulatory oversight directly affect wholesale electricity markets and transmission activities. This oversight indirectly affects competitive retail electricity markets and distribution activities, to the extent that well functioning wholesale markets are important for other services. Federal enforcement of antitrust, environmental, and consumer protection laws also affect the development of competition in markets for all electricity-related services. This section discusses some examples of the impact that federal legislation, federal and state utility regulation, and other federal agencies will have on the development of competitive electricity markets.

Federal Legislation

Historically, the Federal Power Act and the Public Utilities Holding Company Act of 1935 ("PUHCA") have played a large role in determining the configuration of the industry and guided federal oversight of the industry. The Securities and Exchange Commission ("SEC") is charged with the administration of PUHCA. Corporations with a

holding company structure with electric utility subsidiaries that do not qualify for a statutory exemption under PUHCA, such as the "intrastate" exemption for holding companies conducting their utility operations primarily in one state, are required to register with the SEC and are subject to SEC regulation under PUHCA. Registered holding companies are required to operate a single, integrated utility system. Another feature of the law, that has since been somewhat relaxed, limited the diversification of registered holding companies to businesses that were considered incidental or essential for the operation of a single integrated utility system. Registered holding companies are also subject to SEC requirements related to the issuance and acquisition of securities and affiliate transactions. SEC approval is also required under PUHCA in connection with the formation or acquisition of additional public utility subsidiaries by both registered and exempt holding companies. PUHCA created significant barriers to the entry of non-utilities into wholesale electric power markets, but as discussed below, these barriers have been reduced in recent years.

Over the past thirty years, several laws have been enacted that also have affected the industry, including the Public Utility Regulatory Policies Act of 1978 ("PURPA"), the Energy Policy Act of 1992 ("EPACT"), and the Clean Air Act Amendments of 1990 ("CAAA"). Each of these pieces of federal legislation is briefly discussed below.

PURPA requires electric utilities to interconnect with and purchase power from qualifying facilities ("QFs")—co-generators and generators using renewable resources—at prices that in theory are equal to the costs of building new generation by the utility. In practice, QFs have often proven more expensive than the central station alternative.

EPACT streamlined the entry of non-utility generators into the wholesale market for electricity. The law created a new category of power producers, called exempt wholesale generators ("EWGs") which are not considered electric utility companies under PUHCA and do not subject parent companies to regulation as holding companies under PUHCA. By exempting EWGs from most regulation under PUHCA, the law eliminated a major barrier for both utility-affiliated and nonaffiliated power producers who want to build new merchant power plants. EWGs remain subject to regulation under the Federal Power Act. In addition, the law granted authority to FERC to order transmitting utilities to provide wholesale transmission services, contributing to a nationwide open-access electric power transmission grid for wholesale transactions. However, the law specifically prohibits FERC from ordering retail wheeling and, except for requests for specific wholesale transmission services, did not make public power entities subject to FERC jurisdiction. After EPACT was enacted, the SEC also administratively determined that power marketers should not be considered electric utility companies under PUHCA. This permitted many companies to participate in power marketing and brokering at wholesale and retail without subjecting the companies or their parent companies to PUHCA regulation, further fostering competition in those markets.

The CAAA established a new emissions-reduction program, with the intention of reducing emissions of sulfur dioxide and nitrogen oxide from utility sources. The provisions of the CAAA have been implemented largely through a market-based

approach of tradable emissions permits that increase market efficiency by allowing market participants to adjust their emission needs based on their economic incentives rather than fixed emission allowances.

State and Federal Regulation

In addition to the legislation discussed above, state and federal regulations have a broad impact on the development of competitive retail and wholesale electricity markets. For example, FERC Order 888, which requires jurisdictional electric utilities to provide non-discriminatory transmission access for wholesale power transactions, is an important component of the development of competitive wholesale markets across the country. Order 888 also indirectly facilitates the development of competitive retail markets, as well-functioning wholesale electricity markets are an important requirement for well-functioning retail electricity markets.

Another example of federal regulation that has had a positive impact on the development of competitive electricity markets is FERC Order 889. Order 889 requires jurisdictional utilities to distribute information about transmission system capacity, availability, and scheduling through an electronic bulletin board systems known as Open Access Same-time Information System ("OASIS"). Order 889 also requires a utility's merchant operations to obtain information about the parent company's transmission system in the same manner as its competitors—through the OASIS. Order 889 has contributed to the development of wholesale markets by facilitating transparency in the market for transmission services for bulk power transactions and by leveling the playing field. Order 889 also indirectly facilitates the development of competitive retail markets through its impact on wholesale electricity markets.

A more recent example of federal regulation attempting to foster competition is FERC Order 2000. In this order, FERC envisioned a new form of organization administering electric transmission functions, the RTO. This order established a timeline for all public utilities under FERC jurisdiction to participate in a FERC-approved RTO. Order 2000 calls for each RTO to implement congestion management and transmission planning and expansion functions. RTOs will be expected to manage congestion, loop flows, ancillary services, grid expansion and generation siting through pricing and other policies. Each of these services will have important consequences for the development and functioning of wholesale and retail power markets.

In addition to its orders affecting transmission activities, FERC monitors several aspects of wholesale market activity. For example, any FERC-jurisdictional entity wishing to sell electricity at market-based rates must petition FERC for such authority. FERC allows power sales at market-based rates if it determines that the applicant does not have, or has adequately mitigated, market power in generation and transmission and cannot erect other barriers to entry. FERC also considers whether there is evidence of affiliate abuse or reciprocal dealing. In the past, FERC has used the "hub-and-spoke" test to evaluate applications for market-based rate authority. At this time, the agency is considering alternatives to the hub-and-spoke analysis.

An example of federal regulation regarding retail and wholesale competition in renewable energy markets is the Renewable Energy Production Incentive ("REPI") program. REPI is part of an integrated strategy in the EPACT to promote increases in the generation and utilization of electricity from renewable energy sources and to further the advances of renewable energy technologies. This program, authorized under Section 1212 of EPACT, provides financial incentive payments for electricity produced and sold by new qualifying renewable energy generation facilities. Eligible electric production facilities are those owned by state and local government entities (such as municipal utilities) and not-for-profit electric cooperatives that start operations between October 1, 1993 and September 30, 2003. Qualifying facilities are eligible for annual incentive payments of 1.5 cents per kilowatt-hour (in 1993 dollars and indexed for inflation) for the first ten-year period of their operation, subject to the availability of annual appropriations in each federal fiscal year of operation. Qualifying facilities must use solar, wind, geothermal (with certain restrictions as contained in the rulemaking), or biomass (except for municipal solid waste combustion) generation technologies. In addition to REPI, several states have also adopted specific incentive programs to stimulate renewable energy production through a combination of tax credits and state regulations.

At the federal level, price cap regulation can retard the development of a wholesale market, in that some new generators will be unable to construct new capacity based on price signals. If price caps reduce the economic feasibility of a proposed merchant plant, the ability of a supply response (i.e., the construction of additional capacity) to reduce the wholesale price for power will be limited.

In addition to federal regulations mentioned above, there are examples of state regulation that foster competition in retail electricity markets. For example, in Arizona the Commission's rules provide for the licensing of and regulation of competitive ESPs, structural separation of generation from UDCs, and implements open access at the retail level. Also, the rules in Arizona promote the development of green power in the competitive marketplace by calling for all energy suppliers include a minimum amount of solar and renewable energy in their power supply portfolio.

There are also several state regulations or policies that APS believes deters retail competition. First, the Electric Competition Rules do not allow load profiling for small commercial customers. Although the Commission has issued a variance to this prohibition, load profiling for these customers will not be available after the period provided in the variance. Additionally, the Electric Competition Rules specify a processing time for new ESP applicants that APS believes could be streamlined to allow for more rapid certification of these competitive suppliers. Also, the complaint resolution process before the Commission is not designed for competitive ESPs, as opposed to customers. ESPs often need more prompt action in dispute resolution than is currently available. Finally, APS believes that an overly strict, vague or improperly applied "need" analysis in siting power plants (or transmission lines) could adversely impact the wholesale market, in that the continued development of a robust wholesale market

requires the developers of merchant power plants to appropriately respond to price signals.

Other Federal Agencies

Since the revision of the Clean Air Act in 1990, the government has experimented with market-based approaches to provide financial incentives for companies to voluntarily comply with clean air standards and develop new technology for reducing emissions. Last year, the EPA made a significant step in this direction by approving a market-driven air quality program that enables trading of pollution rights in selected states. The EPA did not impose specific reductions on each source. Instead, individual sources are allowed to choose whether and how to reduce emissions or purchase allowances. EPA does not review or need to approve these sources' decisions, allowing them to tailor and adjust their compliance strategies to their particular business needs. In doing so, the EPA made an important effort to increase market efficiency, promote competition and increase overall cost savings.

The Department of Justice ("DOJ") and the Federal Trade Commission ("FTC") also play important roles in fostering retail and wholesale competition at the federal level by providing detailed guidelines for analyzing mergers of electric utilities. These guidelines describe the analytical process used to assess whether proposed mergers significantly increase market concentration and raise concerns about potential adverse competitive effects. In Order 592, FERC adopted the DOJ merger guidelines as its basic framework for evaluating the competitive effects of proposed mergers.

B. How can the Commission protect Arizona customers from the risks of competition while promoting competition?

In some respects, the question should ask "whether" the Commission should protect customers from the risks of competition. In either case, the adage "there is no such thing as a free lunch" applies. Competition implies the ability to make choices, and the ability to make choices implies the possibility that bad choices will be made. Measures taken to eliminate the possibility of bad outcomes lead inevitably to the elimination of any real options from which to choose.

This being said, there clearly are steps that the Commission can take to protect customers. These steps include:

- Adopting or clarifying anti-slamming and anti-cramming rules, truth-in-advertising and disclosure rules, credit-worthiness and bonding requirements applicable to competitive suppliers to protect customers.
- Continuing consumer education, which plays an important role in educating typical retail customers about the risks and potential benefits of competition.

- Allowing the development of competitive retail markets without overly intrusive "command and control" regulation.
- Protecting the financial health of incumbent utilities that retain the legal obligation to serve all customers to prevent the sort of reaction that occurred in California when UDCs were placed in financial distress after being required to absorb high wholesale power costs with no ability to pass the costs through to customers.
- Promoting the construction of needed infrastructure such as power plants and transmission lines.

The most significant measure that the Commission can take to protect customers is to continue to provide an alternative Standard Offer default service based on cost-of-service principles. This "backstop" would protect customers both from the failure of competition to develop and from adverse competitive outcomes. As discussed above, it may turn out that this alternative is so attractive that competition itself is not notably successful. If this is so, it means merely that customers find that the terms of regulated service are preferable. Even under these circumstances, the mere fact that the competitive option exists is a substantial incentive for the Arizona utilities to provide superior service at low prices.

Because of federal jurisdiction, the Commission has a modest role in protecting customers regarding wholesale competition. Its primary role should be to facilitate sufficient entry to make the market competitive and reliably supplied.

C. How have the interim rate reductions for customers receiving standard service affected the ability or desire of generation suppliers to compete in Arizona retail markets?[3]

During the regulatory proceedings and litigation involving the 1999 APS Settlement Agreement, several ESPs argued against granting any rate reductions for Standard Offer customers. These parties asserted that the higher APS' Standard Offer rates, the more attractive the market would be for a competitive ESP. In fact, some states such as Pennsylvania artificially inflated standard offer rates to induce customer shopping.

APS argued, and the Commission agreed, that lower rates for all customers (both Standard Offer and Direct Access) outweighed any short-term benefit to competitive ESPs that artificially high Standard Offer rates would produce. Moreover, because the competitive "benefits" to ESPs from such artificially high rates for Standard Offer Service would have only lasted for the short term, APS does not believe that the rate reductions have had any long-term impact on the competitive retail market for ESPs.

[3] In its response, APS has assumed that this question refers to the rate reductions that were granted pursuant to the 1999 APS Settlement and Decision No. 61973, which were not interim and applied to both Standard Offer and Direct Access customers.

Furthermore, Standard Offer rates are retail rates; a wholesale supplier in an efficient market would be indifferent as to whether it sold to APS or an ESP or another participant in the Western United States. Thus, there is even less reason to believe that the rate reductions have impacted the wholesale generation market.

D. Do Commission policies or legal requirements ensuring that utilities recover investments from ratepayers affect the prospects for competition in any market for which competition otherwise would be possible?

No. In Arizona, incumbent public service corporations such as APS are permitted to engage only in non-competitive services. Thus, regulated utilities' opportunity to recover non-competitive investments would not affect the provision by ESPs of competitive electric services. The retention by APS of provider of last resort obligations necessitates its continued recovery of its actual cost of Standard Offer Service.

The Commission, as well as state and federal constitutional law, requires that rate-regulated utilities have a full and fair opportunity to recover prudent investments in their regulated rates. This does not, however, affect the prospects for competition in any market that is potentially competitive. The prospects for new entry into a competitive market are more affected by the fact that a rate-regulated utility is often the lowest-cost supplier for that product or may benefit from legitimate economies of scale or scope.

Specifically, if a rate-regulated utility is an efficient, low-cost supplier in a particular market, the margin available for a competitor may not be sufficient to warrant market entry. Indeed, one complaint voiced by some ESPs in 1999 to APS' unbundled Standard Offer rates was that the rates were too low to provide a large enough "shopping credit" for the ESPs to make a sufficient profit. However, even if this assertion was true, it would have been inappropriate for the Commission to artificially increase APS' Standard Offer rates to provide increased profits to competitive ESPs.

Also, economies of scale or scope may make competing with a rate-regulated utility difficult for reasons unrelated to regulatory policies for cost recovery. In meter reading, for example, it may be uneconomic for a potential competitor to read meters for two or three competitive customers in a square mile whereas the utility reads hundreds of meters in the same area.

E. Does continuing utility control of depreciated generation assets affect the ability of competing suppliers to enter retail markets?[4]

From an economic standpoint, whether depreciated generation assets are controlled by a utility, a merchant generator or a utility affiliate does not affect the ability of competing suppliers to enter retail markets. However, the presence of those generating assets in the marketplace, regardless of ownership, and the competitiveness of these

[4] In this question, the term "utility" is assumed to refer to an entity with standard offer obligations to retail customers and state-regulated monopoly ownership of distribution services.

assets at the margin will affect the decisions of potential competitors with respect to market entry. The same analysis applies in any competitive market.

There were concerns expressed (by ESPs and Staff) during the rulemaking for the Electric Competition Rules on the potential for cross-subsidization when the distribution function and generating assets are held within the same business unit. Indeed, Staff argued when supporting the 1998 Electric Competition Rules that "only through the divestiture of competitive services or the transfer of competitive services to an affiliate would subsidization and crossovers between monopoly and competition be prohibited." *See* Decision No. 61272 (Dec. 11, 1998) at 33. In Decision No. 61969 (Sept. 29, 1999), the Commission concluded that:

> We agree that the requirement that competitive generation assets and Competitive Services be separated to an unaffiliated party or to a separate corporate affiliate or affiliates, will provide greater protection against cross-subsidization than would separation to a subsidiary.

Id. at 60.

Corporate separation of generating and other competitive electric assets and affiliate codes of conduct offer assurances to potential retail competitors. The existing retail Codes of Conduct for APS and TEP require separate corporate affiliates for utility and competitive activities, with separate books and separate employees (except for officers and directors and certain shared services). Also, transfer pricing is specified and reporting requirements are set. The Codes of Conduct are predicated on corporate separation.

Divestiture of competitive services to an affiliate allows both the new affiliate and the UDC to concentrate and strengthen their core competencies, skill sets, and intellectual capital. It also permits the new affiliate to be a viable competitor with merchant generators, and permits the affiliate to finance generation expansion without reliance on monopoly services for credit support. Finally, locating an existing portfolio of generation in the same entity as is responsible for constructing new generation will permit economies, integration of operations, and coordination of outage and return-to-service scheduling—all of which should aid in the development of competitive markets.

F. How does current Commission regulation promote or deter the ability of (1) renewables, (2) distributed generation, and (3) energy efficiency and demand side management to compete with traditional generation resources?

Current Commission regulations—in particular the Environmental Portfolio Standard—promote the ability of renewable energy resources to compete with traditional resources. Renewable resources generally cannot compete with traditional generation resources on a cost basis, so the Commission's decision to subsidize such resources in the short-term is intended to promote their development in Arizona.

The Commission is working on interconnection standards and processes for distributed generation, which may aid the deployment of distributed generation resources. However, distributed generation is also not cost-competitive with central station power on a large scale. It does have important niche applications that should be more fully explored and utilized once interconnection standards and processes have been finalized, assuming that there would be no grid security or adverse cost impacts.

Energy efficiency is not a regulated service, and is provided on a widespread basis by a variety of service providers. DSM is likewise provided, in various forms, by numerous unregulated energy service companies. DSM was subsidized through a system benefits charge in the past, but when the Environmental Portfolio Standard was passed, the Commission elected to cease significant funding for DSM programs.

G. What are the risks of moving to a regime of retail competition for each product or service and what are the methods for managing those risks?

Answers are provided in tabular format in Table 2.3G, below.

Table 2.3G

PRODUCT OR SERVICE	WHAT ARE THE RISKS OF MOVING TO A REGIME OF RETAIL COMPETITION FOR THIS PRODUCT?	WHAT ARE THE METHODS FOR MANAGING THOSE RISKS?
1. Generation		
Baseload, intermediate and peaking power	1) Temporary imbalances in supply and demand might drive Arizona retail customers away from the competitive market and back to Standard Offer of Service. 2) Price risk: Retail energy markets can be highly volatile until they become significantly competitive. Retail market clearing prices are commonly set by natural-gas fired generation at the margin, which exposes energy prices to additional fuel-price uncertainty.	1) Approve APS' Request for a Partial Variance and the PPA between APS and PWCC, which appropriately balances reliability and price stability with the move towards more competition. 2) Strengthen the competitive market by reducing barriers to entry and increasing market visibility. 3) Whenever retail markets are prone to undue price risk, the Commission should support other procurement strategies that stabilize Standard Offer prices.
Green power	Unless there is a government subsidy or regulatory requirement for minimal green power production, green power resources will be less price competitive than traditional power generation.	Encourage development of cost effective alternatives and operate a separate market for green energy.
Distributed generation	It is not clear when distributed generation technology will be sufficiently advanced to be cost effective and able to compete with traditional generation.	Demand for distributed generation will increase as it becomes more cost effective and price competitive with the traditional generation. NO_x and SO_x emission constraints should only accelerate this process.

PRODUCT OR SERVICE	WHAT ARE THE RISKS OF MOVING TO A REGIME OF RETAIL COMPETITION FOR THIS PRODUCT?	WHAT ARE THE METHODS FOR MANAGING THOSE RISKS?
Firm and non-firm power	1) Demand or volumetric uncertainty. Temporary levels of excessive demand might result with the inexperienced firm power providers not being able to meet all of their load obligations. 2) see (2) in Baseload, intermediate and peaking power	1) Firm and non-firm power contracts should be hedged from a larger pool of resources. Implement risk management procedures. 2) see (2) in Baseload, intermediate and peaking power
Long- and short-term contracts	1) Counter-party risk is the major source of uncertainty for long-term and short-term contracts. Even the largest power marketers are subject to financial distress. 2) see (2) in Baseload, intermediate and peaking power.	1) Strengthening the market for backup services. Credit risk management. 2) see (2) in Baseload, intermediate and peaking power.
Backup services	Temporary levels of excessive demand might result with inexperienced backup service providers not being able to meet all of their obligations.	Backup service contracts should be hedged from a larger pool of resources. Facilitate market for backup services and/or enforce multi-stage power markets to improve market visibility.
Coordination services	Based on recent California experience, it will probably take some time until specific responsibilities of various Scheduling Coordinators are developed.	Enforce communication between the Scheduling Coordinators and system operator via OASIS or some kind of real-time system information posting procedure. Facilitate market for coordination services and/or enforce multi-stage power markets to improve market visibility.
2. Distribution Services		
Metering	Lack of time-differentiated metering and rational energy pricing.	Develop time-differentiated metering and rational pricing procedures.
3. Aggregation Services		
Load profiling	Not Applicable, but there is a risk of cost shifting inherent in load profiling.	Not Applicable. Cost shifting can be reduced or eliminated by requiring interval metering as such metering becomes more cost effective.
Customer services	No significant risks associated with moving to a regime of retail competition.	Not Applicable.
Data analysis	Uncertainty arising from privileged information and lack of market transparency.	Increase market transparency through OASIS posting, market seminars, etc.
Billing	Decreased consumer protection and possibility of slamming and cramming due to loss of regulatory and UDC control.	Develop appropriate consumer protection standards, complaint resolution processes, and protect against slamming and cramming. Also require billing agent to have contractual relationship with UDC or ESP so that a regulated entity can supervise their activities.
Power supply acquisition	Acquisition by multiple entities may cause market inefficiency and higher prices. It may also compromise reliability and supply resource diversity. There are also economies to power supply acquisition	Long-term supply arrangements with proven vendors with adequate generating and financial resources. Also, clarify the Electric Competition Rules regarding supply adequacy and assure adequate supplies of

PRODUCT OR SERVICE	WHAT ARE THE RISKS OF MOVING TO A REGIME OF RETAIL COMPETITION FOR THIS PRODUCT?	WHAT ARE THE METHODS FOR MANAGING THOSE RISKS?
	that would be lost as would accountability for resource adequacy.	available generation.
Demand side management	This service is already competitive and has been for some time.	Not applicable.
Energy efficiency	This service is already competitive and has been for some time.	Not applicable.
Other services relating to matching supply and demand (i.e. ancillary services and must-run generation etc.)	1) Institutional uncertainty: will RTO operate separate markets for various ancillary services and must-run generation and by what means will these markets be integrated with forward and spot energy markets? 2) Volumetric uncertainty: excessive demand levels might result with multiple providers not being able to reliably meet all of their supply obligations. 3) Counter-party risk: inexperienced providers might default and create market inefficiencies in the short term.	1) Support the development of protocols for the provision of ancillary services through RTOs. 2) Resolve the reliability issues discussed under Power Supply Acquisition discussed above. 3) Implement credit risk management procedures.

H. If the current regime is not conducive to retail competition for a particular product or service, what actions should the Commission take to promote its success in the future? Specifically—

1. Should the Commission require existing utilities to procure particular products or services from unaffiliated competitors?

No. They should procure them from whoever offers the best total value. If particular products or services are potentially competitive with utilities' Commission-approved unbundled prices, they will be offered directly to consumers or ESPs. The Commission has fulfilled its appropriate oversight role by ensuring that the prices offered for unbundled service correctly reflect the utilities' costs and provide an appropriate basis of comparison for consumers. Requiring utilities to purchase particular products or services only from unaffiliated competitors likely will increase costs to consumers.

2. Are utilities taking steps that will make competition more difficult down the road (e.g., retail marketing, internal restructuring, entering into agreements to avoid customer self generation)? If so, identify those steps and how the Commission should respond.

APS does not believe that it is taking any steps that will make competition more difficult in the long run. Retail marketing is itself a vital part of competition and self-generation deferral agreements are specifically allowed by the Electric Competition Rules

only when approved by the Commission. "Internal restructuring" is a somewhat open-ended term, but some internal restructuring of UDC personnel is absolutely required for retail competition. Irrespective of whether or not the jurisdiction is moving towards retail competition, internal restructuring should be undertaken whenever it can improve utility performance. For example, APS has had to form internal groups to manage relations with ESPs, handle transmission, supervise Code of Conduct issues, and deal with many other transition issues.

3. Are utilities entering into long-term contracts with existing customers? If so, how do they affect prospects for future retail competition? Should the Commission allow them?

Rule R14-2-1604(C)(6) limits the ability of UDCs to enter into long-term contracts with customers. This rule provides that after January 2, 2001, tariffs for Standard Offer Service cannot include any special discounts or contracts with terms, or any tariff that prevents the customer from accessing a competitive option, other than time-of-use rates, interruptible rates, or self-generation deferral rates. This provision has been interpreted to prohibit contracts in excess of one year unless the contract meets one of the criteria set forth in the rule and to permit multiyear contracts if the customer has a unilateral right of termination after one year.

APS believes that the current restrictions only serve to limit customer choice, and thus would support modifying Rule R14-2-1604(C)(6) to generally allow for long-term contracts, subject to Commission approval.

4. Should the Commission consider instituting competition for billing and metering services even if retail generation competition is premature?

No. Under no retail competition program with which APS is familiar does the customer have the ability to choose a meter service or billing service provider independent of the load-serving entity. Either the UDC (Standard Offer) or the ESP (Direct Access) must control these functions to ensure accurate measurement of services provided and timely accounting and billing.

If, however, the question is suggesting mandatory "outsourcing" by the utility of metering or billing functions, this would likely result in higher costs due to the loss of scale economies. There would also be less regulatory control, because the likely candidates for outsourcing (meter manufacturers and credit card companies) have large, unregulated businesses which are principally out of state. Finally, past instances in Arizona where utilities used non-company personnel (i.e., Southwest Gas Corporation's attempt to use TEP meter readers in Tucson) raised significant safety issues.

2.4 Retail Generation Competition

A. Regarding each identifiable generation product — [5]

1. Identify with particularity any defects in the wholesale market structure affecting Arizona.

The structure of the overall wholesale market in Arizona is competitive by the standards used both by FERC, the FTC and the DOJ. Continued entry by merchant generators will make the market still more competitive. Although the development of some new capacity that is either already certificated or announced may be postponed or cancelled, new capacity additions should still contribute to further development of the regional wholesale market, even if the new capacity is not specifically available to Arizona buyers. Further, Arizona is but a smaller component of the overall Desert Southwest or WSCC wholesale market, which from a market standpoint adds to the robustness of wholesale competition and makes state or utility-specific issues less significant to wholesale market participants.

That said, there are issues with the wholesale market in generation which led APS to conclude that it would be unwise to "flash cut" to obtaining all generation requirements from the market on January 1, 2003. As discussed below, there is insufficient competing generation not already committed to other loads to guarantee that a competitive procurement for half of APS' load would be successful in disciplining prices. APS also concluded that, apart from the difficulties of the initial procurement, its customers would not be well served by substituting competitively procured generation fueled almost entirely by natural gas for the diverse portfolio offered by PWCC. While the Desert Southwest wholesale market is structurally competitive, competitive does not mean the same thing as stable. Significant price volatility for APS' service area in the near future is a possibility and price volatility as compared to the proposed PPA a near certainty. Also, the transmission system to serve APS' load requirements was not designed to accommodate all of the generation coming from one market hub (Palo Verde/Hassayampa, for example). Rather, the transmission system would require that a significant portion of the generating capacity come from areas with existing APS/PWCC generation (such as Cholla/Four Corners and Navajo). Since virtually all new uncommitted generation is being constructed in the vicinity of the Palo Verde hub, significant amounts of that new generation may be unable to physically supply APS' requirements.

There are also load pockets (such as the Valley, Tucson, and some smaller areas) where local generation must run under some circumstances. Thus, owners of generation in these load-constrained areas must be subject to mitigation measures or the pricing of capacity in these areas will not be wholly "competitive."

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[5] Since there are not distinct markets for the various generation products defined in Section 2.1, the answers to Questions 2.4(A)(1) through (5) refer to all generation products in Section 2.1.

A final structural issue is the fact that there is as yet no RTO covering the wholesale markets that include Arizona. RTOs will play an important role in developing the markets for such generation-related products as coordination, back-up, and ancillary services, as well as assuring that markets for energy and transmission service function more efficiently. When established, WestConnect should fill this gap.

2. Are there an adequate number of competitors to sell in Arizona to make the product sufficiently competitive? How many sellers are there?

APS would note that none of the merchant generators constructing power plants in Arizona are retail suppliers. The only entities authorized to sell electricity to consumers at retail are certificated ESPs and UDCs through Standard Offer service. Only some of the merchant generators—such as Sempra and PG&E National Energy Group—have affiliates that have been certificated as retail ESPs, and none of these ESPs is currently active in Arizona.

However, there are a large number of wholesale suppliers and traders in the Western wholesale market of which APS is a part. This number of participants and the regional basis of the wholesale market means that wholesale power is competitive in Arizona in the aggregate.

Suppliers physically located in Arizona include Southern California Edison, Public Service of New Mexico, El Paso Electric Company, PacifiCorp, PP&L, APS, PWEC, SRP, Arizona Electric Power Cooperative, TEP, Reliant, and Calpine. Also, new power plants are under construction by PP&L, Duke Energy North America, Panda/TECO, Sempra, PG&E National Energy Group, and probably others. Finally, given the liquid trading hub at Palo Verde, there are literally dozens of traders and power marketers making transactions in Arizona.

3. How have mergers and consolidations in the industry affected the competitiveness of the product in the region at the wholesale and retail levels?

None of the entities listed in response to the previous question have been engaged in mergers and acquisitions that have reduced the number of competitors in Arizona. The only geographically relevant activities other than the construction of new plants involving these entities have been Duke's purchase of generation in California and PacifiCorp's acquisition of Utah Power & Light, which might otherwise have been independently active in the Western market. The Department of Energy, Energy Information Agency's Annual Electric Utility Report reflects 16 power marketers, 29 private utilities and 5 federal entities that are active in Western wholesale markets. There are over 40 merchant generators in the WSCC that are either operating plants or scheduled to commence operations in 2002. In addition, there are hundreds of other utilities, mostly municipalities and cooperatives, many of which own generation and participate in wholesale markets. It is unlikely that mergers will lead to noncompetitive wholesale market conditions in the foreseeable future.

4. Are competitors building new generation able to price their generation at rates competitive with existing generation?

This question cannot be answered with a simple yes or no. APS does not know the specific pricing strategies or details of merchant generators building new capacity in Arizona. However, the long-run marginal cost of new natural gas-fired merchant capacity is likely above the blend of the costs reflected in APS' proposed PPA. Thus, if the question is whether APS' load, or a portion thereof, could be met by competing generators pricing their generation at long-run marginal cost, thereby earning a market rate of return on their investments, the answer is probably not. In addition, because existing generation is not sufficient to meet APS' load requirements in 2003 additional resources must be acquired, and it is logical to assume that much of these additional resources will come from new generation.

5. How has the Independent System Administrator affected the success of (a) retail competition and (b) wholesale competition?

The AISA has accomplished its goal of acting as a transitional organization on the road to an RTO, and has established Direct Access protocols which APS has incorporated into its Open Access Transmission Tariff. Moreover, as a result of the AISA's efforts, a portion of the most valuable constrained transmission facilities that were designated as network service for the UDC have been allocated on a non-pro rata basis to encourage retail competition. As such, APS believes that the AISA has helped lay the necessary groundwork for the development of a competitive retail market by making adequate transmission capacity available to ESPs to serve retail loads. Although the AISA's role is limited to retail competition, the WestConnect RTO will aid the development of the competitive wholesale market. Accordingly, APS believes that an RTO—as has always been contemplated in the Electric Competition Rules—will still be necessary to further develop competitive wholesale and retail markets in Arizona.

B. Regarding the transmission and distribution infrastructure necessary to support competition for each identifiable generation product—

1. Are there transmission constraints inside or outside Arizona that currently impede the ability of competitors to reach Arizona customers during any seasons of the year or times of the day?

There are congested transmission paths in several locations in Arizona and the Western United States. For example, there is significant transmission congestion on Path 15 between Northern and Southern California, which impedes the ability of hydroelectric power to flow from the Pacific Northwest to the Desert Southwest in the summer. There is also occasional transmission congestion in Northeast Arizona and from Palo Verde to the Valley.

Transmission congestion can result when there is not enough transmission capacity to meet demand in a certain area, or when there is not enough generation to meet load within a constrained area, or when there is more generation competing to sell on a particular transmission path than the transmission system can handle. However, transmission congestion—which affects all users of the transmission system—does not necessarily impact retail competition because transmission rights follow retail load. If an APS Standard Offer customer elects to receive Direct Access service, the transmission rights to serve that customer's load are allocated from APS to the retail supplier. The retail supplier gets the same transmission rights that APS had to meet that customer's load.

Transmission facilities have been planned over many years to ensure that there is adequate transmission capability to reliably serve retail customers. The system was never designed so that every unknown future merchant generator, wherever sited, could access every potential customer delivery point, wherever located, on demand. No generator or group of generators would be willing to pay for such a system. Indeed, many Arizona generators sited their plants and requested only interconnection service. These generators did not make any arrangements for transmission service independent of their interconnection, intending to place that obligation on the hoped-for but then unknown buyers of their output.

Additionally, the current system depends on a mix of local generation and transmission to provide voltage support and meet demand in urban areas. Local generation is a necessary and useful element of an integrated electric grid that provides increased reliability to the system. Thus, adding redundant transmission facilities in an effort to eliminate reliance on local generation is neither cost-effective nor desirable.

Today, enough transmission capacity exists to accommodate the import and export of all Palo Verde interconnected capacity through 2002. By 2003, the planned transmission projects of APS and SRP will further expand that capability. However, if all publicly announced generating units to be interconnected at Palo Verde are actually built, merchant generators would probably have to request some additional transmission capacity beyond that already planned to simultaneously access desired markets. Such new transmission capacity would not be needed to serve load, and therefore would have to be economically justified or funded by merchant generators or other third parties.

2. What plans are in place to relieve transmission constraints?

APS, as well as other Arizona utilities, generators, and federal power marketing administrations, have plans to construct additional transmission in Arizona. Significant projects to relieve local import constraints include the Palo Verde to Southwest Valley 500 kV project (2003), the Palo Verde to Southeast Valley 500 kV project (2006), and the Palo Verde to Table Mesa 500 kV project (2008). The Palo Verde to Southeast Valley project has been proposed by SRP, and APS is considering

participating in the project. There are numerous other projects which are included in APS' 2002-2011 Ten Year Plan, which was filed with the Commission on January 31, 2002. These projects and others will provide additional transmission import capability to accommodate load growth.

In the future, transmission system planning will be largely undertaken in concert with WestConnect through an open, top down-bottom up process that includes all stakeholders, generators and transmission providers. The WestConnect model is designed to meet load needs and ensure competitive market access at the lowest possible cost. To achieve this, WestConnect will establish a Regional Transmission Expansion Plan on at least an annual basis, with input from a transmission planning workgroup in which the transmission owners will be required to participate and which will be open to all WestConnect stakeholders, generators and interested parties. Any participating transmission owner, such as APS, or any market participant may propose a project to be included in the Regional Transmission Expansion Plan. Additionally, on at least an annual basis, each participating transmission provider will be required to provide its ten-year expansion plan for its service territory. The Regional Transmission Expansion Plan will be easily accessible through a posting on the WestConnect website.

In its plan formulation, the independent board of WestConnect will consider proposed expansion plans of market participants, grid reliability, obligations to serve native load, economic and environmental considerations, and the continued development of a robust competitive wholesale marketplace. WestConnect upgrades will consider economic alternatives such as additions or expansion of generating units, the use of DSM or distributed generation, and other alternatives such as potential replacements, additions, or expansions of facilities. Participating transmission providers are responsible for siting, permitting and constructing facilities on their systems to support WestConnect upgrades. Costs of new facilities will be recovered through the transmission provider's access area rates when the facilities are owned by the transmission provider and through WestConnect grid charges when owned by WestConnect or a third party.

3. How long will it take to relieve any existing transmission constraints and what factors are affecting and will affect prospects for relief?

The planned transmission additions discussed above should relieve known transmission constraints from a reliability perspective. However, transmission constraints will ebb and flow with load growth, as new transmission lines are constructed, and as new generation is sited. APS does not believe it appropriate to "overbuild" transmission at its customers' expense simply to accommodate a speculative need for any given merchant power plant to reach any market in the West. Also, with Valley load approaching 9000 MW, APS believes there will always be a desire for local generation in the summer to maintain system reliability.

4. Are the owners of constrained transmission facilities, or holders of transmission rights, able to use their control to affect market prices?

For FERC-jurisdictional transmission owners such as APS, transmission rates are regulated on a cost-of-service basis with wheeling directed pursuant to Order 888. These transmission wheeling rates must be posted on OASIS systems and cannot be resold for profit. Thus, there are no market-based transmission rates at this time. Public power entities are not directly regulated by FERC, but many have reciprocity tariffs on file with similar provisions to FERC-jurisdictional entities.

Regarding wholesale markets generally, owners of constrained transmission facilities or holders of transmission rights are not able to use that control to affect market prices in the long term, and are limited in their ability to affect short-term prices. With respect to the long term, owners of transmission facilities are subject to orders under the Federal Power Act that can mandate the construction of new transmission facilities to eliminate the constraint, subject to state siting and other requirements. In addition, to the extent transmission service is available on such constrained facilities, it must be provided on a non-discriminatory basis, at least with respect to those providers that are subject to FERC jurisdiction. With respect to the short term, holders of transmission rights may be subject to investigation for hoarding and not using the transmission capability; moreover, to the extent they do not use their rights, transmission service may be available to others on a non-firm basis. Finally, the rights to constrained transmission facilities used to serve native load customers goes with that native load; to the extent the retail customers change providers, the new providers can use the existing transmission rights over such facilities. Also, under the Allocated Retail Network Transmission ("ARNT") provisions of APS and TEP transmission tariffs, a portion of the most valuable constrained facilities has been allocated on a non-pro rata basis to encourage retail competition.

5. Are these transmission owners currently doing things that will allow them to exert more or less control in the future? If so, please detail.

Transmission owners, including APS, TEP and SRP, that currently support WestConnect are creating mechanisms that will promote the elimination of transmission constraints and the beneficial use of existing transmission which will facilitate competitive markets.

6. Will the transmission system be adequate prospectively (e.g., in the next, 5, 10, 15, 20 years) to deliver power from new generation plants?

This is difficult to forecast because it depends on which new generation plants are actually built, where and when they are built, their total capacity, and what loads are served. Of course, it would be imprudent to plan a transmission system that allowed for the simultaneous transfer of all generation along all possible transmission paths. Also, the siting and construction of new transmission adds to the electrical analysis

associated with interconnecting new generation to the grid. With this said, it is possible that in the short term, the transmission system may not be adequate to simultaneously accommodate all new planned generation. However, there will still be the need for ancillary services and reserves from some plants, in addition to dispatched power. APS believes that transmission is and will be adequate to serve its retail customers. Moreover, in the long term, WestConnect should be involved in long-range planning to address these issues.

7. ***Is the natural gas pipeline infrastructure adequate to support all proposed new gas-fired generation plants? How many plants can it support?***

Most new gas-fired generating plants in Arizona are to be sited on or near the El Paso Natural Gas south mainline. Based on current pipeline operating capacity, APS does not believe enough physical capacity exists on this pipeline to support peak demand requirements of all current and proposed gas-fired generation. The number of gas-fired generating plants that can be supported is a function of day-to-day conditions related to load demand and market price, so APS cannot answer "how many" plants can be supported. APS would, however, note that two significant gas storage projects have been announced for future construction in Mohave County. These projects should mitigate the natural gas constraints discussed above.

8. ***Does the transmission and distribution system facilitate or deter—***

   (a) the development of renewable energy technologies?

   (b) the development of distributed generation?

   (c) the development of demand-side management and energy efficiency?

Transmission and distribution facilities (that is, the actual hardware) would not, generally speaking, have any direct impact on the development of renewable energy technologies when renewable energy technologies operate as substitutes for central station resources.

In general, utility delivery systems have not been planned, engineered, constructed and operated to effectively, efficiently and safely interconnect with distributed generation installed by customers. Thus, the new technologies often require investments in hardware and processes. These additional costs, less any demonstrable system benefits, should be recovered from those who impose the costs on the system, thus deterring unsound investments. In contrast to distributed generation, DSM and energy efficiency equipment is generally installed on the customer side of the meter. Such technologies therefore do not manifest the same issues as discussed above, and are not generally affected by facilities on the transmission or distribution systems.

C. Regarding competitive bidding—

1. Identify with particularity any adverse consequences that would result from Commission approval of a substantial variance to the electric competition rules that require competitive bidding for 50% of the electric supply for standard offer customers, starting in 2003. Specifically:

(a) How would retail customers be affected?

There would be no adverse consequences to retail customers resulting from any such variance to Rule 1606(B). Retail customers benefit from reliable power supplies at stable and reasonable prices. To the extent that a variance to Rule 1606(B) of the Electric Competition Rules improves generation supplies to Standard Offer customers, it will benefit customers who take Standard Offer Service. Conversely, a Standard Offer Service that becomes less attractive as a result of a variance in the rules will be less valuable to customers. APS believes that the variance it is requesting benefits its Standard Offer customers in all respects without in any way prejudicing those customers wishing to try Direct Access.

The fact that Arizonans have retail access creates a "win-win" opportunity to the extent that Standard Offer prices are formed on a basis different from the competitive generation market underlying retail Direct Access service. The ability to move off Standard Offer Service if it becomes economically unattractive to a customer means that if, contrary to APS' expectations, the proposed PPA is at higher-than-market rates for generation, retail customers could avail themselves of the lower rates in the retail Direct Access markets. If, as APS expects, the proposed variance and PPA reduce costs to Standard Offer customers relative to the costs absent a variance, customers are protected from the higher and more variable prices in the competitive market.

(b) How would retail generation competition be affected?

There should be no net negative effect on retail generation competition. Indeed, even if one were to posit a "market" consisting only of sales to meet APS' Standard Offer requirements, Mr. Davis discussed in his testimony in the variance proceeding the substantial opportunities that will remain available to competing generators. These include an increasing competitive bid component between now and 2008 (a total of 1,620 MW) and the provision of Supplemental and Replacement Energy Products.

If retail generation competition means competition to serve retail loads in Arizona, granting the proposed variance and approving the proposed contract with PWCC would eliminate a competing generator's opportunity to compete for the load that will be covered by the contract, but would not eliminate the ability of that generator to compete for retail load through an ESP. Thus, the result of the proposed

contract would remove a like amount of PWCC capacity and energy from the market in which the remaining generators compete. Since the PWCC capacity has as low or lower costs than competing capacity (or locational and flexibility advantages that are not duplicated) the PWCC capacity will find its place in the market. The sole effect on competing generators will be that they would forgo some of the Standard Offer portion of the market, but not the remaining competitive market for retail Direct Access, exports, and supplemental energy. These markets are materially larger than the portion of the market at issue in the variance. In fact, the Arizona, New Mexico and Southern Nevada region accounted for only 16.6 percent of loads and 15.9 percent of resources in the WSCC in 2000.

(c) How would wholesale generation competition be affected?

As explained by APS' testimony in Docket No. E-01345A-01-0822, the variance that APS is proposing would not affect the supply and demand balance in Arizona or the southern WSCC. Hence, the total demand to be met and the market price at which the market should clear are not affected by the proposed variance.

2. Are sufficient competitors available for an effective bidding process for 50% of standard offer service? A higher or lower percentage?

As discussed above, APS believes that current market conditions do not support competitively bidding 50 percent of APS' Standard Offer load in 2003. All existing non-PWCC merchant competitors in Arizona combined could not meet half of APS' load beginning in January 2003. APS has no specific knowledge of out-of-state generators interested in bidding for APS' load (or of all in-state or out-of-state obligations already accrued by merchant generators in Arizona). There is certainly a lack of geographical diversity of new merchant generators, most of whom are locating near the Palo Verde hub. Further, generators competing from outside of Arizona would have to deal with pancaking of transmission rates and compounding of line losses until an RTO is functional in the Desert Southwest, increasing the cost to competitively serve Arizona customers. If this analysis is spread across all UDCs and load serving entities in Arizona, APS believes that a significantly lower percentage of Standard Offer service could be effectively bid out, but such specific percentage would depend on the area in question and the projected date of such bidding.

3. Can retail competition develop if current rules are modified to allow a utility to procure all its generation for standard service from an affiliated company?

First of all, the current rules would allow a utility to obtain all of its generation from an affiliated company if that affiliated company won that portion of the load that was competitively bid and was selected by the UDC. The issue is not related to the affiliation of any specific generator, but on the relative price levels of generators, and between Standard Offer Service and Direct Access rates that a competitive ESP is willing to offer customers.

Standard Offer Service is a non-competitive service. Retail competition will succeed or fail depending on whether competitors can provide price and non-price terms to customers that the customers find more attractive than Standard Offer Service. Thus, if a modification of the rules results in a more attractive Standard Offer, retail competition may suffer in the short term, but customers will benefit from lower prices.

4. ***How would retail competition be affected by other deviations to the competitive bid rules? Be specific about the changes in the rules and their consequences.***

It is not likely that any change to the "competitive bid rules" would adversely affect retail competition in Arizona. That competition is primarily dependent on the absence of legal and regulatory barriers to market entry, flexible pricing authority, and stability in the wholesale generation market. Indeed, retaining the existing competitive bid requirement could hurt retail competition and especially retail customers by making Standard Offer Service an unattractive alternative for those customers most likely to rely on such service.

5. ***Instead of entertaining individual requests for substantial variances to the competitive bid requirements, should the Commission proceed on a generic basis to modify the rules for competitive bidding?***

Prior to the Company's October 18, 2001 filing, the Commission was already considering a variance request to Rule 1606(B) filed by Citizens Communications Company. Subsequent to APS' filing, TEP has requested a simple one-year delay rather than a comprehensive alternative proposal such as the Company's. No other investor-owned Affected Utilities—and only investor-owned Affected Utilities are subject to Rule 1606(B)—have filed requests for variances. Each of the three companies that have asked for modification or postponement of Rule 1606(B) are uniquely situated and are making discrete proposals that do not lend themselves to generic treatment. Moreover, the Commission has used the variance procedure outlined in Rule 1614(C) even when all Affected Utilities were requesting the identical variance. *See, e.g.,* Decision No. 63316 (January 11, 2001) (permitting all Affected Utilities to engage in competitive metering and meter reading for residential customers despite prohibition in Rule 1615).

6. ***If the Commission would change the 50% bidding requirement for standard offer service, are there other specific measures the Commission can take to promote retail competition?***

As noted above, the bidding requirement is independent of the issue of retail competition. That being said, APS believes that there are several specific measures that the Commission can take to promote retail competition, including the following:

- streamlining the certification process,
- exercising the authority to waive regulatory requirements intended for monopoly services as permitted under House Bill 2663,[6]
- removing one element of legal uncertainty by submitting the Electric Competition Rules to the Attorney General as directed by Judge Campbell,
- providing strong regulatory support for WestConnect, and
- preserving Standard Offer Service and those entities that provide it as viable economic options for customers.

D. Regarding the pricing of power supply contract rates—

1. Identify any advantages that would result if the Commission approved a long-term supply contract for standard offer customers that was based solely on cost-based rates. (Your answer should define "long term" as compared with "short term" contract.)[7]

The relevant facts are the terms of the contract, not whether a contract is styled as a market or cost-based contract. Formally, the contract proposed between PWCC and APS is a market rate contract under PWCC's market rate tariff. However, as explained in APS' testimony in Docket No. E-01345A-01-0822, the terms of the contract are generally derived on a cost-of-service basis. The benefits associated with a long-term PPA like the one proposed by APS include:

- Overall price stability and predictability with an increasing market-based component.
- Fuel diversification of generation resources leading to lower prices and less volatility based on natural gas price fluctuations.
- Geographic and technological diversification leading to increased reliability.
- Proven track record of plants involved on a system that was designed to accommodate the mix of plants reflected in the PPA.
- Customers can leave Standard Offer service if the competitive market produces better results than the PPA.
- Ownership of a responsibility to provide reliable supply.

If, however, the focus is solely on the fact that a contract is long term and is not tied to escalating and fluctuating market prices, the primary benefits are that the contract price is likely to escalate less rapidly than the market price since the latter is closely related to the price of gas, which is expected to escalate in real terms. Also, such a contract is likely to be far less volatile than the spot, day-ahead, month-ahead and annual market price, since these also are affected by the price of gas as well as by

[6] Commission Staff agreed to conduct a generic investigation concerning such waivers during the course of the Commission's consideration of the 1999 APS Settlement.

[7] Long- versus short-term can have significantly different meanings based on context. For purposes of this question, however, APS would define a long-term contract as a contract of five years or longer.

the "boom-bust" cycles in the wholesale generating market and by the vagaries of weather. Either shorter term market-based contracts or long-term contracts that have clauses that relate contract terms to market prices will suffer by comparison.

2. What if the contracts are based solely on market-based rates?

See the answer to the previous question. If the contract merely provides for the sale of a specified amount of power at rates periodically trued to the market (e.g., daily or annually), the risks of this to APS in the context of retail access and its customers are self-evident. In California, where the UDCs could not pass purely market-established wholesale costs through to customers due to rate freezes, this ultimately caused the collapse of direct access and bankruptcy or near-bankruptcy for affected utilities. Likewise, customers paying solely market-determined rates are confronted with price volatility and the potential for significant rate shock.

3. Describe how FERC's new approach for analyzing the ability of sellers with market rate authority to exercise market power affects generation companies selling into Arizona.

FERC recently modified its approach to analyzing requests for market based rates. In a Staff Discussion Paper on September 20, 2001 and in a subsequent order on November 20, 2001,[8] FERC announced its intent to abandon the "hub and spoke" test used previously to determine whether to grant market rate authority in favor of a Supply Margin Assessment ("SMA") test. Briefly, the test as illustrated in the November 20, 2001 order compares the peak load in a control area to the total amount of supply to the area. The supply is applicant's total installed capacity, all other installed capacity within the control area, and the sum of uncommitted capacity outside the area that can reach the area using the total transmission capacity into it. If capacity not owned by applicants is sufficient to meet the control area peak load (without reserves) then the test is passed and the applicant is granted market rate authority within the area. If it is failed, the applicant is deemed to be "pivotal" in meeting load in the area and market rate authority is granted only along with mitigation requirements. Sales within FERC-approved RTOs and the existing ISOs are exempt from the test.

The test, which was specifically labeled "interim" and soon to be replaced with a more permanent test, has attracted significant adverse comment. In any event, it appears that all of the generators selling into the Arizona market would pass the test. Indeed, the nature of the test almost assures that merchant generators will not fail. A merchant generator, by definition, has not dedicated its capacity to meet anyone's native load on a long-term contract basis. A merchant generator can be pivotal only if the load serving utility, plus all inbound transmission, plus any other capacity in the service area (e.g., Southern California Edison's share of Palo Verde) is insufficient to

[8] *AEP Power Marketing, Inc., et al.*, 97 FERC ¶ 61,219 (2001).

meet the control area load. Thus, even if the SMA test survives, the same entities that received, or on completion would have received, market rate authority under the hub and spoke test will receive the same authority under SMA and it should not affect generating companies selling into Arizona.

4. Does the Commission have the ability to assure that approval of a long-term contract would protect ratepayers receiving standard offer service as well as foster competition?[9]

Yes, as long as the contract does not also prohibit customers from returning to Standard Offer Service and as long as "fostering" competition does not entail creating artificial subsidies to benefit competitors instead of competition. In fact, the continued availability of reasonably-priced Standard Offer Service provides an important back-stop, especially for residential and small commercial customers often ignored by some competitive energy providers. It also sets a standard of price, reliability and service by which larger customers can measure the often bewildering variety of offers they may receive from ESPs.

As noted above, a principal advantage of Commission approval of a long-term contract to be used in conjunction with a UDC providing Standard Offer Service is that such contracts can manage price volatility and reliability concerns for customers, while not affecting the ability of ESPs to compete for Direct Access customers. Even with long-term contracts associated with providing Standard Offer Service, the Electric Competition Rules continue to allow customers to choose Direct Access service if pricing or other reasons justify switching by that customer.

Under this model, competitors will continue to seek to develop competitive offerings or obtain power below the price offered by the UDC without the Commission having to subsidize new entrants by pricing Standard Offer Service above the cost at which such power could be supplied (i.e., the long-term contract price). If the competitor can obtain (or construct) generation that beats the price in the UDC's long-term contract, customers will presumably switch to the competitor. Thus, as long as the long-term contract does not prohibit customers from opting into or out of Direct Access, the Commission can accomplish both of the stated goals—protecting ratepayers without harming the development of the competitive market.

[9] APS assumes that "protecting" Standard Offer customers means protecting such customers from market volatility and uncertainty.

2.5 Industry Events External to Arizona

A. Describe in detail developments you believe will occur in both the wholesale and retail competitive electric generation markets nationally and in Arizona over the next 12 months, 24 months, 36 months, 48 months and 60 months.

It is impossible to accurately predict what exactly will happen with retail and wholesale competitive electric generation markets over the next sixty months. Where within that sixty-month window an event will fall (12 months, 24 months, etc.) is even more uncertain. However, these markets have shown certain trends over the last couple of years that are likely to continue in the near future.

First, following FERC Orders 888 and 889 and Order 2000, various Independent System Operator or RTO structures have been established across the nation. While some of these structures became fully operational, the others are still under development or were put on hold. In general, these entities tend to foster competition by facilitating energy and capacity markets, providing information on a non-discriminatory basis to all market participants and ensuring overall system reliability. APS certainly expects WestConnect to be functional well before the 60 months noted in the question. WestConnect will bring precisely the type of market rationalization and efficiency envisioned by FERC in Order 2000.

Second, energy markets have been highly cyclical over the last couple of decades. There have been numerous boom and bust cycles across many regions in the United States and abroad. This may ultimately lead to future power shortages and a return to sky-high electricity prices. Although boom and bust cycles are somewhat natural to many commodity markets and will, to a certain extent, always remain present in energy markets, new market mechanisms might decrease their magnitude in the future. In particular, strengthening the forward markets for energy and capacity should foster overall market liquidity in the long term.

Third, there is significant proposed federal legislation on the energy front. Although such legislation may not pass this year with the nation, Congress, and the Administration focused on the war against terrorism, it is more likely that some form of legislation would be enacted over the course of the next five years.

Fourth, as wholesale markets become either more stable or "hedgable," there should be renewed interest in direct access both in Arizona and across the country. The success or failure of the highly-touted direct access program in Texas will also have a significant impact on the way customers throughout the United States view direct access, just as the California experience has soured many customers and regulators on electric competition and restructuring.

In this regard, it is critical to a successful Direct Access program in Arizona to have the "safety net" of a reasonably-priced and reliable Standard Offer Service. This will make customers more willing to "test the market." APS intends to preserve the economic

attractiveness, reliability and availability of that Standard Offer "safety net" through the proposed long-term PPA with PWCC.

B. Is there anything the Commission should do to continue to avoid California's retail electric competition experience? Please be specific.

There are many factors which when combined, helped precipitate and exacerbate California's energy problems. These include but are not limited to:

- **Natural gas prices**: a dramatic an unexpected rise in natural gas prices (about four times higher in late 2000 than in 1999);
- **Strict pollution control measures**: limited regulatory allowances for nitrogen oxides, particularly in southern California, which in turn led to a sharp increase in the costs of these allowances which were necessary for many units to run and which significantly added to their marginal costs;
- **Weather patterns**: unseasonably hot weather in the summer (especially in northern California where temperatures climbed above 100 degrees Fahrenheit in early June 2000) and cold weather in the winter months along with low hydro conditions;
- **Insufficient supply**: strong growth in electricity demand in the West which restricted western states' ability to export power to California;
- **Uncertainty as regards restructuring**: uncertainty regarding the way in which the restructured system was to work, which led to delays in new plant construction inside California;
- **Poor retail pricing signals**: fixed rates which insulated end-users from the high cost of power, thus discouraging appropriate demand response early in the crisis;
- **Loss of creditworthiness**: as they became increasingly caught in a price squeeze between high wholesale power costs and fixed retail rates where the wholesale costs of power could not be passed through to consumers, California UDCs lost financial credibility thus further limiting their ability to use financial and hedging to lessen commodity price volatility;
- **Poorly designed wholesale market**; and
- **Reluctance to site new generation within the state.**

For the purposes of this question, however, the most significant structural factor leading to the energy crisis in California was the development of a poorly designed wholesale market. As adopted, the energy procurement policy in California was short-term and prescriptive in nature. Long-term contracts were not allowed and bilateral contracts were discouraged. All power was purchased for consumers in a spot market under a bidding system that kept prices at relatively low levels when demand was low relative to supply. However, when demand was high, prices rose to very high levels. This volatility could have been hedged for at least part of the utilities' demands. For several reasons, however, utilities in the state did not cover significant portions of their

summer load in this fashion, subjecting either them or their consumers to the volatility of the market.

Given this background, there appear to be several policy objectives that the Commission should consider to help ensure that Arizona is spared the California experience. This policy agenda includes:

- **Generation**: maintain a favorable investment and regulatory climate for both affiliates of incumbents and merchant generators to ensure that enough generation capacity is online and ready to meet load growth;
- **Long-term procurement**: foster the development of supply arrangements for Standard Offer customers at stable prices over extended timeframes (*e.g.*, long-term power purchase agreements and forward contracts);
- **Siting and infrastructure development**: streamline the siting process and ensure that enough infrastructure (transmission capacity and natural gas pipeline capacity) is in place ready to meet growing needs and system reliability requirements;
- **Customers**: encourage retail customers to participate in real time-pricing and voluntary load-reduction programs;
- **Divestiture**: continue to support measures aimed at minimizing horizontal market power and vertical market power; and
- **Financial health**: maintain the financial strength of providers of last resort and honor prior regulatory commitments.

C. Does the Enron bankruptcy have any lesson for retail electric competition in Arizona?

To the extent that the development of a robust retail market in Arizona and elsewhere is dependent upon the maturation of a liquid and transparent wholesale market, the Enron bankruptcy will likely yield both short-term and long-term consequences. However, it is important to note that despite the fact that Enron was the nation's largest marketer of gas and electricity, its collapse has so far had little to no effect on the supply or price of electricity in the retail market. In fact, the Enron bankruptcy has few if any immediate and direct impacts on the development of a retail electric market in Arizona or elsewhere. Rather, the impact of the Enron case is far more likely to affect accounting standards.

Specifically, however, the Enron situation demonstrates that the degree to which a retail supplier, or a wholesale supplier on which a retail supplier relies, is not financially sound or adequately hedged may eventually impact the availability and price of energy and capacity sold at retail. This emphasizes the importance of the availability and security of Standard Offer Service and suggests that the financial requirements for suppliers should be carefully drawn up and enforced.

Finally, as a result of the fallout from Enron, many companies have delayed or cancelled investments in new capacity and some are selling assets, raising the possibility of tight supply markets when economic growth eventually picks up. In addition, equity prices of many energy companies have declined significantly, credit ratings have been downgraded by credit agencies, and the costs of raising capital to make needed investments in the nation's energy supply infrastructure are steadily rising, adding at least some new risk to reliance on new or planned merchant capacity for retail end users or ESPs.

D. How will FERC's RTO initiative affect the realization of effective retail generation competition in Arizona?

Conceptually, an RTO will help consumers (generally through ESPs) access more generation resources located in a very large geographic region in a non-discriminatory manner under prescribed rules, prices and protocols. Certain barriers presently exist that might otherwise economically preclude retail competition from a practical standpoint. For example, pancaked charges for transmission service, would be eliminated by virtue of an operational RTO. Additionally, FERC requires the RTO to be the provider of last resort for ancillary services including balancing services further facilitating competitive markets. And, the RTO will also provide a market monitoring function for the wholesale power markets, which is the first line of defense against the exercise of market power. All of these should help realize retail competition in Arizona.

E. Do you anticipate changes in federal utility statutes to affect the jurisdiction of the Commission and its ability to foster retail competition in Arizona? Please detail.

There currently are numerous bills related to electricity before Congress. Many bills concern federal budget appropriations or tax issues, and thus would be unlikely to affect either the Commission's jurisdiction or the Commission's ability to foster retail competition in Arizona. However, there are at least two bills currently before Congress with some likelihood of being passed that contain provisions that may affect the Commission. Whether the current Congress will or will not pass comprehensive energy legislation, or how such legislation would be modified from the various bills now being considered, is impossible to predict. Nonetheless, below APS has attempted to briefly highlight some of the more significant legislation that, if passed, could be responsive to the question.

S. 1766, "The Bingaman Bill"

Two provisions of the Bingaman Bill that may affect the Commission include:

- Requirements relating to net metering for certain eligible distributed generating units up to 500 kW, which might affect the utility's ability to charge appropriate standby, interconnection or other charges, and additional metering.
- A renewable portfolio standard requirement for each retail electric supplier.

The Bingaman Bill contains many other provisions that relate to utility service but may not directly affect the Commission including:

- Extension of FERC jurisdiction over non-FERC-jurisdictional entities to ensure comparable open access rates, terms and conditions, with exemptions for smaller unregulated transmitting utility.
- Repeal of PUHCA and the PURPA purchase requirements.
- Increase in the threshold for FERC review of mergers from $50,000 to $1,000,000 and expansion of FERC jurisdiction to include acquisition of generation facilities, natural gas facilities and holding company mergers.
- Amendments to the Federal Power Act providing factors that FERC is to consider in determining whether market-based rates are just and reasonable.
- Requirements that each broker, exchange or other "market-making entity" in the wholesale market provide on the Internet statistical information about the amount and sales prices of the sales it transacts, with protection for privileged, confidential or sensitive commercial or financial information.

H.R. 3406, "The Barton Bill"

Three provisions of the Barton Bill that may affect the Commission are:

- Requirements for net metering for eligible distributed generating units up to 250 kW that would permit the utility to charge any incremental distribution and metering costs and provides for the states to set appropriate rates.
- "Backstop" federal siting authority to FERC to issue permits to site or modify transmission facilities when states do not act.
- Directs FERC to require each transmitting utility to participate in a fully operational RTO no later than 12 months after enactment; requires FERC to issue a proposed rule to ensure uniform market rules, including appropriate seams agreements; and specifies standards for RTOs previously defined in FERC Order No. 2000.

The Barton Bill contains many other provisions that relate to utility service but may not directly affect the Commission including:

- Expands FERC jurisdiction to include currently non-jurisdictional entities in order to ensure comparable open access rates, terms and conditions, with exemptions for smaller unregulated transmitting utilities.
- Repeal of PUHCA and the PURPA purchase requirements.
- Repeal of FERC merger authority in Section 203 of the Federal Power Act.
- Expands FERC investigative and refund authority to include currently non-jurisdictional entities.

Tax Issues

Congress is also considering legislation on federal tax-related issues that may have an effect on retail competition. Two such provisions included in H.R. 4 are:

- Provisions for a deferral (and extension of the replacement period) of gain from the sale of electric transmission assets to implement FERC or state electric restructuring policy, and the non-recognition of gain on distributions of stock to implement FERC or state electric restructuring policy.
- Provisions related to nuclear decommissioning trust funds which would:
  - Repeal the limitation on deposits into a fund based on cost of service.
  - Allow continued contributions even after the funding period.
  - Clarify the tax treatment of fund transfers necessitated by divestiture or restructuring.
  - Confirm that decommissioning costs are deductible when paid.

2.6 System Security

A. Are there compelling reasons to be concerned about security for electric generation facilities since the Sept 11, 2001 tragedy? Please include discussion of interconnection at a central location such as Palo Verde/Hassayampa.

Certainly concern about security for electric generation facilities and other critical infrastructure has increased since the events of September 11, 2001. Rendering multiple generating stations unavailable for long periods of time could threaten the ability to meet electrical demand, potentially leading to curtailments. Due to the interdependence of other critical infrastructure on electricity, APS and other electric power suppliers take very seriously any threats or potential threats to such service.

The issue of critical infrastructure security, however, was not born from the events of September 11, 2001. Over three years earlier, in May 1998, President Clinton signed Presidential Decision Directive 63 ("PDD-63"), which recognized that certain critical infrastructures—including telecommunications, energy, banking and finance, transportation, water systems, and emergency services—are essential to the minimum operation of the national economy and government. PDD-63 established as a national goal the protection of these critical infrastructures from intentional hostile acts.

The Department of Energy was designated the lead agency for implementing PDD-63, and the North American Electric Reliability Council ("NERC") was designated lead agency for the electricity sector. Together, these agencies working with the industry established a Working Group for Critical Infrastructure Protection. In turn, the Working Group has developed a four-tier security model, including (1) avoidance through prudent policies, standards and procedures, (2) assurance through the regular evaluation of both physical and cyber security, (3) detection through monitoring, identification, central

reporting and analysis of threats and incidents, and (4) recovery and restoration, including the incorporation of lessons learned into the other tiers. The efforts of the Working Group are ongoing.

Although APS will not reveal or discuss its specific security programs in this public document, APS actively monitors the Critical Infrastructure Security program and continues to tailor its specific security measures based on the results of the Working Group and other industry participants. APS believes that the industry is making substantial strides in better protecting critical infrastructure from both physical security threats and the growing threat posed by cyber-terrorism.

Regarding specific security issues, the simultaneous outage of multiple generating facilities could compromise the security of the transmission grid and cause curtailments. Although the impact of such a scenario would be significant, the risk of multiple outages or damage to multiple generation facilities is considered low because of existing and recently improved security measures at major power plants.

The risk is probably no greater for concentrated generation areas such as the Palo Verde/Hassayampa switchyards. In fact, the risks there may be lessened because of the increased overall security and awareness at sites of multiple facilities, and in the case of Palo Verde, the presence of significantly heightened security at the nuclear plant. Also, even though these facilities are relatively close to each other, they are still spaced far enough apart that it would be unlikely that one attack could damage more than one generating facility. APS will continue to work within the federal and industry forums to manage the security risks associated with these facilities.

B. Does transferring ownership of generation facilities out from traditional Commission jurisdiction have any potential negative security consequences?

Security has at least two aspects. One is the physical security of the generation facilities themselves, while energy security is more a reliability concept that deals with issues such as fuel and technology diversity, and geographic dispersion. From a physical security standpoint, transferring ownership of generation facilities from Commission jurisdiction would not likely have negative security consequences. Several federal agencies or bodies already have jurisdiction or are active in Critical Infrastructure Protection, as was discussed above. At nuclear plants, the applicable Nuclear Regulatory Commission and Federal Emergency Management Agency plans would continue to apply. At non-nuclear facilities, the operator would work with the National Infrastructure Protection Center ("NIPC") and the NERC's Information Sharing and Analysis Center ("ES-ISAC"), along with other appropriate governmental authorities.

The other aspect of security—energy security—is a concept that suggests that a state should diversify the resources from which its energy needs are supplied, both geographically and by resource type. APS does not believe that transferring ownership of generation facilities will result in any negative energy security consequences for several reasons. First, Arizona already has a broad diversity of generation resources on which to

draw—including coal, natural gas, nuclear, hydroelectric, and landfill gas to name the more significant resources. The ownership or regulatory jurisdiction of these facilities does not affect their impact on Arizona's energy security situation. Second, there is already geographical diversity among Arizona's generation, including numerous critical plants that are actually located out-of-state or jointly owned and operated with non-jurisdictional entities. In fact, plants located in Arizona are partially owned and operated by several out-of-state utilities. Finally, because the wholesale market in the Western United States is regional in nature, it is very unlikely that the transfer of regulatory authority would alter the operation of the wholesale market for power in any way that would impact Arizona's energy security.

C. What if ownership after transfer results in a foreign corporation eventually controlling Arizona's generation?

Virtually all the new merchant plants being built in Arizona are owned by foreign corporations, and several existing plants are totally or partially owned by such entities (Cholla 4, Navajo, and the Palo Verde Nuclear Generating Station, for example) All the major gas pipeline capacity in place or being planned in Arizona is and will be foreign-owned. Thus, the specter of out-of-state corporations doing significant energy business in Arizona has been with us for a long time.

APS does not believe it is likely that a single foreign corporation could ever "control" a majority of Arizona's generation. However, if such an event did occur, presumably such an entity would not have market based rate authority and would have to offer generation at cost-based just and reasonable prices. Moreover, given transmission system limitations, it is unlikely that a foreign corporation could withhold capacity, or sell outside the state, in sufficient amounts to jeopardize Arizona's energy security. If multiple foreign corporations controlled Arizona's generation, they still could not withhold capacity or manipulate pricing without violating applicable state and federal laws.

Finally, it is extremely unlikely that the state of incorporation has any bearing on a corporation's business behavior. If such a corporation were to own generation in Arizona and sell it out-of-state, it will almost certainly be for economic, contractual or legal reasons unrelated to its domicile state's parochial interests.

D. Does such a transfer to a non-Arizona entity potentially impact security issues for Arizona?

See responses to Question 2.6 B and 2.6 C, above.

E. Are there any positive security aspects to transferring electric generation out from Commission traditional regulation to a foreign corporation?

There are no specific security benefits to transferring generation to a foreign corporation as contrasted to a domestic corporation such as PWEC. There are, however,

benefits to utility customers from transferring generation from traditional regulation. These benefits include reducing customer and UDC exposure from the increasingly risk-laden generation business. This would relate to the concept of "energy security" addressed in the Company's response to Question 2.6 B.

F. Provide specific examples to support your answers.

Examples of security measures and potential security impacts are provided in the Company's responses to Question 2.6 A. Examples of "foreign" companies that already own or control generation in Arizona include, for example, Panda/TECO, PG&E National Energy Group, Reliant Energy, Sempra, Duke Energy North America, Southern California Edison, El Paso Electric, Nevada Power Company, PacifiCorp/ScottishPower and Public Service Company of New Mexico.

2.7 Vision

Please provide your vision for how viable competitive wholesale and retail electric markets will (or will not) develop in Arizona. Please be specific regarding dates, the development process, and measures for determining at various stages how successful the process has been.

Structurally, the Arizona wholesale market is reasonably competitive, albeit volatile and unpredictable. Changes in it will be evolutionary rather than revolutionary. Because Arizona participates in a larger market, any discussion of wholesale markets in Arizona necessarily entails a view of this wider market.

In the near term, the improvement in supply and demand balances that began last summer will continue to take pressure off of prices and supply adequacy in the region. Restoration of water reservoir levels will restore a more normal pattern of inter-regional trade, in particular relieving Path 15 power flows north from the Desert Southwest and Southern California. A 50 percent increase in the capacity of the Path 15 tie, scheduled for 2004, will further broaden inter-regional trade.

Presuming that FERC succeeds in its RTO initiative, as appears likely, the Arizona FERC-jurisdictional transmission owners and transmission system users will be part of WestConnect. The boundaries of that RTO are not yet finally established, but if FERC follows through in reducing "seams issues" among RTOs—a less daunting task than the establishment of the RTOs themselves—the physical scope of the RTO will become relatively less important. FERC will seek to have the RTOs fully functioning by no later than the end of 2003, with some functions turned over earlier. Less clear is whether the public power entities that are not FERC jurisdictional will be compelled to join or will join voluntarily.

In the near term, it is likely that there will be excess generation supply in the larger market where wholesale power prices in Arizona are set. How long this will persist depends on how much of the planned capacity is built, the rapidity with which retail prices in California are reduced from current high levels, how much obsolete capacity (primarily in California) is decommissioned, and the vagaries of weather and the business cycle. Large capacity reserve

margins could and most likely will lead to prices that will not return the full cost of new generation for the period of excess. Low prices, or indeed market recognition that they are coming, as already is taking place, could cause new supplies to cease entering the market by approximately mid-2003. This will set the stage for a period of reserve margin tightening and, quite possibly, another future period of inadequate supply and increased price volatility.

In viewing the prospects for wholesale market performance, it is important to consider the role of Arizona in the overall Western grid. Competitive wholesale prices in Arizona are and likely will continue to be driven by prices in California, no matter how much one might wish to disconnect them. FERC rules and the Constitution will not permit interference with interstate trading so that one state can benefit at the expense of another. For related reasons, in a competitive context "integrated resource planning" and state-level analyses of supply sufficiency are largely obsolete concepts. Because of certain inherent advantages as a site for power plants relative to southern California and southern Nevada, Arizona is likely to continue to export electricity. Accordingly, Arizona competitive prices should rise to scarcity levels long before Arizona itself faces any capacity deficiency and irrespective of who owns or controls the power plants in Arizona.

One tool that most commentators agree is useful or even vital to help the wholesale market to self-regulate supply and demand imbalances is to create more interruptible demand, preferably through real-time demand response to spiking energy and capacity prices. While the metering, tariff and contract offerings supporting demand response are retail activities, they have important implications for preserving reliability and moderating price spikes at the wholesale level. However, demand response is somewhat more limited in its potential in Arizona than in many other areas due to relatively small industrial process use of electricity and the prolonged elevation of temperatures on peak days.

While wholesale market operation will fall primarily within the purview of FERC, the Commission has a number of significant roles to play. It has the power to limit (or expedite) supply through its facility siting authority—though the California experience and the openness of interstate trading caution against artificially restricting supplies. The Commission continues to have a role in encouraging "green power," potentially beyond that which customers will elect voluntarily by taking service from green retail access providers or under green tariffs. It can also play a major role in creating price responsive demand.

The crystal ball about retail competition is cloudier. As discussed above, mass-market retail access may not take root if customers can remain on Standard Offer Service at prices at or below market. If the Commission wants to see retail competition substituting for Standard Offer Service for the mass of customers, it must either force them to leave Standard Offer Service or cause the state's utilities to increase Standard Offer prices to above market—neither of which are measures that APS believes are appropriate. However, a few state commissions have done this. Even some that thought that they were doing so failed to, when increasing gas costs raised market prices to above frozen standard offer tariffs. Most, however, have sought to keep standard offer prices at or below market by either continuing to cost-regulate generation, using buy-back contracts with generation affiliates that are effectively cost of service, or by allowing the pass-though of power acquired at market rates with no significant mark-up.

Looking out farther into the future, it is difficult to tell whether retail access will succeed or fail on a national level. Either of two paradigms is likely. Which prevails will depend on whether consumers and policymakers conclude that despite the attraction of choice, there simply is not enough scope for superior performance in retailing to merit the regulatory, marketing, and other costs of retail access.

Additionally, the likelihood of successful mass market retail access depends on the behavior of the existing utilities. When retail access first was given serious consideration in the early 1990s, many utilities were perceived as unresponsive to customers, bloated and inefficient, and less competent than non-utilities in purchasing fuels and services and buying and generating power. The threat of competition has had a very salutary effect on utilities. Had they not changed, it is likely that retail access would have been more popular and more successful.

PWCC and APS remain committed to retail access. They equally are committed to providing reasonably-priced, reliable, and high-quality service to customers through the Standard Offer. Both objectives are satisfied by APS' proposed variance and the Purchase Power Agreement. To APS, such a strategy will offer a "win-win" situation for its customers regardless of what developments occur in the foreseeable future.

SECTION III
COMMISSIONER SPITZER'S JANUARY 22, 2002 LETTER[10]

3.1 Renewable Energy Issues

1. In a vertically integrated utility model, what incentives (regulatory, financial and ratemaking) exist for the expanded use of renewable energies?

APS has long attempted to foster renewable energy programs that meet customer demand for such energy. However, traditional regulatory principles required rate-regulated utilities to engage in least-cost planning and to only acquire resources pursuant to such planning. Renewable energy technologies (excluding hydro) were not and are not cost-effective compared to existing fossil and nuclear generation facilities or even to new gas-fired plants. Thus, under traditional regulation, it was often necessary for renewable energy sources to receive explicit or implicit regulatory support or for the cost of the renewable to be "bought down" through government or private contributions.

Explicit regulatory support includes mandatory programs directly funded through rates, often through a dedicated revenue source especially created for that purpose. Implicit regulatory support occurs when voluntary utility programs to foster renewables generally receive full recovery during general rate proceedings. Additionally, APS believes that it is important to provide for cost-benefit or similar analyses of such programs to ensure that a program is effective from both a policy and practical standpoint.

Government contributions to utility renewable programs can come in several forms, but most often are in the form of tax credits or direct grants. Private contributions may come from large foundations, public interest groups such as the Law Fund, or from individual ratepayers of the utilities.

This last type of renewable program, in which consumers are willing to pay more for renewable energy, is particularly popular under both industry models. For example, the Department of Energy reports that "more than 80 regulated utilities spanning nearly 30 states offer 'green pricing' programs." In Arizona, APS has implemented several green power initiatives, including Solar Partners. In virtually all of these cases, including the Solar Partner program, participants are not required to pick up the entire additional cost of renewable energy. Thus, the balance of the shortfall in absorbed by the general body of the utility's customers as an example of implicit regulatory support of the type discussed above.

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[10] For purposes of all of its responses, APS considers the period of time prior to 1999 as the "period of reliance on the vertically integrated utility model" and the period since 1999 as the period "since Arizona's adoption of a competitive electric market model." APS also interprets the term "vertically integrated utility" to refer to an electric public service corporation having the exclusive right to sell electric power at retail within a specified geographical area whether or not the utility is actually vertically integrated in the economic sense (e.g., APS) or is simply an electric distribution company (e.g., Citizens Communications Company).

In its response to Question No. 5, APS will discuss in more detail some of the other renewable programs that have received either explicit or implicit regulatory support from the Commission under what the Question describes as the vertically integrated model. Suffice it to say that regulators and utilities were influenced to support renewables under this model for precisely the same reasons they do today—environmental concerns, desires to help develop the renewable technologies as part of long-term resource diversity, and economic development of local industries. The industry model does not affect the motivations of regulators and utilities in promoting renewable programs, but it can affect their ability to essentially force electric consumers to pay for these programs.

One way to promote renewable resources and technologies without impacting utility rates (an important consideration under either industry model) is direct government or private grants. Government has to some extent provided tax incentives and direct grants. Attached at Appendix __ is a copy of the Joint Committee on Taxation, *Description of S. ____, "Energy Tax Incentives Act of 2002"* (JCX-2-02), February 11, 2002. This document both provides a discussion of each present tax incentive for renewable energy and other energy efficiency-related programs and a discussion of proposals now being considered by Congress for such incentives.

To the extent that government permits the monetization of environmental benefits through tradable emissions credits programs, this can constitute an indirect form of government contribution to renewable energy. Regulators under either model can and should promote the initiation of additional tax incentives or more refined pollution trading credit programs that provide financial incentives to invest in renewable technologies and use renewable energy to serve the utility's customers.

2. In a competitive market model, what incentives (regulatory, financial and ratemaking) exist for the expanded use of renewable energies?

Profitability is the primary incentive in a competitive energy model. If enough consumers are willing to purchase "green power" at premium rates, there are profits to be realized. In fact, actual experience in other states that have restructured energy markets suggests that there will be providers other than the incumbent utilities that will offer consumers electricity from renewable sources and that some customers are willing to pay for green power. The Department of Energy reports that there are eight marketers supplying green power in Pennsylvania, two in New England states, and two in New Jersey. According to the California Energy Commission, last year in California there were three providers of wholesale green power and six retail providers. Giving competitive providers pricing flexibility and the ability to segment their potential market (i.e., only serve those interested in green energy at whatever price they can get in the market) creates a powerful incentive for these types of providers to actively market renewables under this particular industry model.

In several states, the free market has been considered inadequate and as a component of the restructuring process, regulators have developed programs to affirmatively

encourage the development of green power. In California, for example, consumers who sign up with a Commission-approved green power marketer are eligible to receive a subsidy. Regulators may also choose to require that the state's overall generation mix include a certain minimum amount of energy from renewable technologies and at least attempt to provide rate recovery for any non-economic costs.

In the regulated model, regulators can promote the initiation of additional tax incentives or pollution trading credit programs that will provide financial incentives to invest in renewable technologies. Private entities can also contribute as under the vertically integrated model.

3. In a vertically integrated utility model, what disincentives (regulatory, financial and ratemaking) exist for the expanded use of renewable energies?

Renewable energy is generally is more costly than electricity generated from fossil fuel plants. If regulators require resources to be purchased on a least-cost basis, renewable energy will be disadvantaged under most circumstances. Such regulatory disincentives may either be direct (e.g., resource planning regulations requiring least cost and prohibiting the acquisition of non-approved resources) or indirect (higher cost of renewable energy resources disallowed in rate setting). Because of the lack of regulatory support and approval, the financing of major renewable projects by utility companies is difficult if not impossible.

4. In a competitive market model, what disincentives exist for the expanded use of renewable energies?

As under the vertically-integrated model, cost is the issue along with the presence or absence of customer demand for renewable energy products. Moreover, most competitive firms have higher required rates of return than do regulated utilities, thus discouraging even those projects with positive long-term economics. As noted above, these can be at least partially off-set through product differentiation, aggressive marketing, pricing flexibility and government programs such as the Environmental Portfolio Standard.

5. During Arizona's period of reliance on the vertically integrated utility model, what renewable energy programs were enacted in Arizona?

These answers are specific to APS and will address the period of time prior to 1999 as the "period of reliance on the vertically integrated utility model" and the period of time since 1999 as the "adoption of a competitive electric market model."

APS' involvement in renewable energy dates from the 1950s when APS helped establish the first solar energy group in the world. In the 1970s, APS built the largest photovoltaic system in the world up to that time. These efforts led to the development of the APS Solar Test and Research Center (the STAR Center), where APS, with the Commission's approval, began a comprehensive program for the development and testing

of solar technologies. At the STAR Center, APS tested and developed as many as 40 different solar and related technologies.

Up to 1999, APS solar programs were funded through the EEASE Fund program. EEASE is an acronym for Energy Efficiency and Solar Energy. This program provided APS with $3 million per year to pursue a goal of developing 12 MW of cost-effective solar capacity. Most of this funding went directly to testing and development of solar technologies with the objective of developing cost-effective solar technologies.

The result of that program was APS' introduction in 1994 of the Remote Solar Electric Services where APS began providing customers that live off-grid (greater than one-half mile from power lines) solar electric systems as an alternative to a conventional line extension. APS currently has provided systems to 39 customers (residential and commercial) under this program and publicized the solar option to hundreds of such customers each year.

In 1996, APS launched its Solar Partner program, the first such program to be offered to customers by any utility in the state. This is a "green power" program where customers have the option to pay a small premium each month to support the development of commercial solar generating technologies.

As a result of the Solar Partner program, through the end of 1998, APS built nearly 500 kW of commercial solar power plants throughout the state and signed up over 1500 customers as Solar Partners. All the money contributed by Solar Partners is used to fund the construction of additional solar power plants in Arizona.

In addition to solar, APS has participated aggressively in the testing and analysis of other renewable technologies such as wind, landfill gas, fuel cells, and microturbines as possible future renewable energy sources for our customers. Hydrogen technologies, fuels cells and microturbines have also been evaluated at the STAR Center. APS has also been a leader in the development and testing of alternative fueled vehicles.

6. Since Arizona's adoption of a competitive electric market model, what renewable energy programs have been enacted in Arizona?

With the introduction of the competitive electric market in Arizona, APS continued to expand the STAR Center, provide off-grid customers with a solar option and grow the Solar Partner program. The STAR Center has been instrumental in the development and first deployment of concentrating solar technologies that use the most efficient photovoltaic cells in the world. The STAR Center has played a key role in the development of dish-stirling technologies. Also, at STAR, two new methods of tracking photovoltaic systems have been developed and tested, leading to the deployment of hundreds of kW of new solar power plants by APS. APS continues to provide off-grid customers with the option to choose solar over a line extension. 10-15 customers per year typically choose this option.

In 2000, APS transitioned the Solar Partner program from the sale of 100 W increments of solar generating capacity to selling 15 kWh blocks of solar energy for a premium of $2.64 per 15 kWh block of energy. This is to help mainstream the purchase of solar power for customers into the more familiar kWh realm for energy sales. By 2002 over 2,800 APS customers had purchased one or more 15 kWh blocks of electricity with several commercial customers choosing to pay in excess of $500 per month to support the use of solar generating technologies by APS. APS currently has 1.23 MW of commercial solar generating capacity on line to support these customers' needs.

In 2001, the Commission adopted the Environmental Portfolio Standard, a rule that calls for all electrical distribution companies to provide a minimum of their energy from renewable resources including at least half from solar beginning in 2001. APS will collect about $6 million per year from customers to help meet this requirement, and APS has met this requirement in 2001. APS will install about 1 MW of additional solar in 2002 and expects to install or participate in the installation of 4 MW of biomass projects.

3.2 Generation Construction Incentives and Disincentives

7. Under the vertically integrated utility model, what incentives exist to build newer plants that are less damaging to the environment to replace older, dirtier plants?

As a preliminary matter, not all new plants will be "less damaging" to the environment than existing plants. Many existing plants are remotely located in areas where any environmental impacts affect fewer people, or use pollution control equipment that makes them relatively clean compared to other facilities (both electric and general industrial). Further, retiring existing plants may require other trade offs, such as diminished fuel and geographical diversity which could affect overall system reliability, increased operating costs, and lost investment from commissioning new plants and retiring existing facilities. And, newer plants may involve trade offs among impacts, such as lower air emissions but higher water use or higher visual and land use impacts.

Over time, a utility will build new capacity to meet growing demand. These facilities, which use current generation technology, generally operate "cleaner" in an empirical sense than older plants, thus reducing average emissions. In order for a newer facility to actually replace an existing plant, one returns to the same considerations as discussed in response to Question Nos. 1 and 3. In other words, under the vertically integrated utility model, the only incentives are economic and regulatory, and since the economic incentives to the utility are largely dictated by regulatory action, it is really the latter that is the primary incentive.

If the newer, cleaner plant also reduces the utility's revenue requirements, the incentive to construct is direct and compelling. If it does not, regulators (which include environmental regulators) must do one of two things—either change the economics of the situation or mandate the newer plant irrespective of economics.

The effective cost of the newer plant can be reduced indirectly through regulatory initiatives such as environmental credit trading programs or more streamlined siting procedures for newer plants. The more direct way is through ratepayer or tax subsidies for the newer facilities.

The latter change can come either through the resource planning process or through resource portfolio mandates. Although traditionally focused on least-cost planning, many states also factored resource diversity and environmental externalities into their planning process. Similarly, portfolio standards effectively establish a technology quota system that is more or less independent of economic considerations, at least in the short-run.

8. Under the competitive electric market model, what incentives exist to build newer plants that are less damaging to the environment to replace older, dirtier plants?

The incentives are the same as under the vertically integrated model—economics and regulatory mandates. Indeed, the reason that newer plants are generally "cleaner" than existing plants has little to do with the identity of the project developer (utility or merchant) or the degree of utility commission regulation but more with (1) the enactment of stricter emissions and pollution control requirements by environmental agencies, and (2) technological improvements partly driven by these stricter requirements. However, the means by which these incentives can be realized, especially on the economic side, can be significantly different. Over the past several years, companies have built or announced plans to build tens of thousands of megawatts of new generation capacity in the West. The extent to which these newer units displace the older units is dependent upon the ability of these newer plants to produce energy at costs below the marginal costs of the older units. However, it is clear that the new breed of generators has pricing flexibility and the ability to freely access diverse markets both in and out of the local region that gives their facilities added value in this competition.

Stricter environmental regulation along with tradable environmental credit programs effectively raise the costs of older units and reduce the costs of newer units. The fact that the economic gains thus realized by new entrants are not capped by rate-of-return regulation makes the incentive for more efficiency and, not coincidentally, more environmental benefit all the greater. Moreover, the ability to realize extraordinary returns on one generation of plants makes it easier and cheaper to secure financing for the next generation of plants, thus potentially accelerating the process of technological innovation even further.

As under the vertically integrated model, regulators can attempt to alter the economics of the "old versus new" competition through environmental regulations and siting policies. Similarly, tax policies and government funding of new generation technologies (e.g., fluidized bed coal plants or biomass generators) are also incentives that work under either model.

9. Under the vertically integrated utility model, what disincentives (regulatory, financial and ratemaking) exist to build newer plants that are less damaging to the environment to replace older, dirtier plants?

If regulators require such decisions to be based solely on economics or reliability concerns, it is often difficult to justify a new plant even if it has lower operating costs in addition to superior environmental performance. This may be because the older facility (which may be in full compliance with applicable pollution limits) has much lower fixed costs than the new facility, thus offsetting its higher operating costs. In such an instance, the older plant would not be replaced, at least in the short term. This would also be the case under a competitive model, so the economic disincentive to premature retirement of generation is not a one unique to regulation.

Another disincentive under either regime is the difficulty in siting new facilities. Often they cannot be sited at all or only under conditions that make it difficult to compete with existing plants not under similar restrictions. Because the number and location of available new sites is limited, they tend to cluster around transmission hubs, leaving them subject to transmission congestion not faced by the existing, more geographically diverse portfolio of generation.

However, under regulation there may be an economic disincentive to replace the older unit even if the older facility also has higher fixed costs because traditional ratemaking necessarily considers recovery of sunk costs in evaluating the economics of new resource additions. Thus, the savings from the new plant may be offset completely or at least for some period of time by the need to also recover the undepreciated cost of the old plant that was built with regulatory approval and in furtherance of a utility's obligation to serve. Raising rates, even if only in the short run and in the interests of longer term net benefits, is politically unpopular and creates issues of intergenerational equity (i.e., why should today's ratepayers pay for the benefits to tomorrow's ratepayers). This disincentive is unique to cost-of-service regulation because under competition sunk costs are irrelevant to incremental resource decisions.

Another disincentive to any large new construction under traditional regulation is the general inability of utilities to raise prices during construction of the facility to help reduce the financial burden of such construction. Although the Commission has on occasion allowed construction work in progress ("CWIP") in rate base, this has been the exception and is usually accompanied by the imposition of long-term financial penalties on the utility's shareholders. This again is largely unique to regulation since competitive firms can raise prices whenever market conditions permit.

10. Under the competitive electric market model, what disincentives exist to build newer plants that are less damaging to the environment to replace older, dirtier plants?

A competitive market is driven by profitability. Whether a generator can sell its output for a profit will have little to do with whether it is less damaging to the

environment or whether it displaces older plants. In the response to Question 9 above, the Company discussed some of the general disincentives under competition to new plant construction. However, APS would add that increased public and regulatory opposition during the site selection process against what are perceived as largely "unnecessary" (from the standpoint of reliability) merchant plants may discourage companies seeking to build new facilities.

3.3 Certificates of Environmental Compatibility

11. During Arizona's period of reliance on the vertically integrated utility model, what emphasis did the Commission place on pollution control measures in Certificate of Environmental Compatibility?

(a) What is the most stringent pollution control measure placed on a CEC during Arizona's reliance on the vertically integrated utility model?

For the purpose of this question, APS assumes that the period of reliance on the vertically integrated utility model referred to above covers the timeframe before the granting of a CEC to Griffith Energy, which was the first so-called "merchant plant" to be authorized in the state, on November 18, 1998. Even with this assumption, however, it is difficult to meaningfully respond to this question because siting cases are very case specific and largely driven by the Commission then empanelled to address each decision. Moreover, the stringency of conditions is necessarily driven by the context—a seemingly minor environmental condition may significantly impact the ability of an applicant to obtain financing for a project, while a seemingly significant condition may be achievable with current industry-standard equipment. Thus, while the latter situation may be more stringent from an empirical perspective, the former may be the most restrictive from a practical perspective. Also, it is impossible to empirically compare the relative "stringency" of conditions addressing different issues, such as whether a given land use restriction is more or less stringent than a given condition relating to water use, wastewater discharge, air emissions, visual impacts, or archeological impacts.

In all CECs, the Commission and the Siting Act have required compliance with all applicable environmental laws and requirements. Such specific environmental requirements are largely determined by the agencies with primary jurisdiction for the particular medium in question, such as the Arizona Department of Environmental Quality for air emissions or aquifer protection permits. Thus, the Commission has unquestionably emphasized pollution control measures in all siting cases that have been before it. Of course, specific conditions differ and more recently the trend of the Commission has been to include more numerous express conditions to CECs.

The Commission has also included specific pollution control conditions in siting cases before 1998. For example, in one of its earliest CEC grants to the Cholla Generating Station for expansion of its facilities (Case No. 7), the Commission required the applicant to actively monitor the visibility impacts of the new additions both during and after completion of the plants. The Commission also conditioned the CEC on an

assurance from the applicant that it would operate its particulate and sulfur dioxide removal equipment as close to design efficiency as possible. Other conditions were integrated into the CEC addressing the location and treatment of the plant's ash disposal area.

Through 1976, the Commission retained many of the conditions attached to the Cholla CEC, but often added the extra requirement that the applicant design and adopt a water management plan subject to approval from the Arizona Water Commission (Case Nos. 7, 16, 18, and 19). In 1976, however, the Commission introduced more complex and intensive water management conditions on an applicant's CEC (Case No. 22; January 22, 1976). The Commission specifically required the applicant to design and develop a groundwater plan to be approved by the Arizona Water Commission. The CEC was also granted upon the condition that the applicant install and maintain a pipeline that transferred the effluent from a sewage plant to the applicant's plant.

From 1976 until 1998, the Commission continued to impose water and groundwater management conditions on the applicants similar to those mentioned above. More notably, in 1977, the Commission also required TEP to monitor ambient air quality and collect related data until the proper Arizona environmental authorities established their own monitoring programs (Case No. 30; August 3, 1977).

12. Since Arizona's adoption of a competitive electric model, what emphasis has the commission placed on pollution control measures in Certificates of Environmental Compatibility?

(a) What is the most stringent pollution control measure placed on a CEC since Arizona's adoption of a de-regulated utility model?

As noted above, some recent siting cases have included more express conditions than cases prior to 1998. However, because some of the first merchant plants approved by the Commission (i.e., Griffith and Reliant Desert Basin) did not contain any more or different conditions than earlier pre-1998 siting cases, and some recent utility-sponsored cases (i.e., Santan) contained significantly more stringent and more numerous conditions than merchant plants, the specific measures included in a CEC do not appear to be affected by whether the market is vertically-integrated or competitive. Rather, the added conditions appear to result from case specific circumstances.

Regarding the most stringent condition imposed after 1998, the case-specific circumstances described in the response to the previous question again apply. Of course, the denial of the CECs of two projects based at least in part on environmental impacts (i.e., Caithness Big Sandy and Toltec) are significant. Of those post-1998 CECs approved, there have been significant conditions regarding air emissions (including BACT, BACT plus, LAER requirements, specific control technologies, and the periodic review and potential retrofitting of new technologies) and groundwater consumption (including recharge requirements or express limits on groundwater withdrawals). There are also wastewater conditions, including requirements regarding the use of zero

discharge design. But there are also many other conditions, not all of which are "pollution control" measures, that are significant to individual applicants. APS believes that the most stringent CEC issued for a generating project to date is likely the Santan CEC issued to SRP. Again, however, many of the pollution control conditions in that CEC are probably mostly a product of the urban location of the plant and are not related to whether the applicant is vertically integrated or a merchant generator.

(b) What is the likelihood that that measure would have been placed on a similar CEC in a vertically integrated utility model?

See response to Question 12(a).

3.4 Excess Generating Capacity

13. During Arizona's period of reliance on the vertically integrated utility model, what amount of excess generating capacity existed in Arizona?

APS is not aware of any "excess generating capacity" in the sense of there being installed capacity built or acquired by Arizona utilities that was not used to serve Arizona consumers. Nor is APS aware of any generic Commission finding of excess capacity throughout the state for any particular time period. This is not to say that there was not capacity available for sale out-of-state during periods of low in-state demand. There was also capacity in Arizona owned by out-of-state utilities used to serve those utilities' customers' demand, but APS would not consider such capacity to be "excess" within the meaning of this Question.

14. Since Arizona's adoption of a competitive electric market model, what amount of excess generating capacity existed in Arizona?

In the economic sense, the terms "excess" or "surplus" and, conversely, "shortage" are less relevant in a competitive market. Prices adjust to bring demand into balance with whatever supply is available at a point in time. Supplies expand so long as there is profitable demand left unserved. However, the lack of centralized planning inherent in a competitive generation market and the inability to tie specific resources to specific markets (i.e., merchant generation is often not dedicated to the customers of any specific geographical area) may tend to make competitive generation markets more susceptible to "boom and bust" cycles with corresponding price volatility. This has been the experience in most commodity markets and to a somewhat lesser extent in the previously regulated airline, ground transportation, and natural gas industries.

SECTION IV
CHAIRMAN MUNDELL'S JANUARY 30, 2002 LETTER

4.1 Corporate Structure and Affiliate Relations

1. If the U.S. Congress repeals the Public Utility Holding Company Act of 1935 ("PUHCA" or "ACT") PUHCA—

(a) what regulatory protections would be lost for Arizona consumers?

(b) what would be the risks for Arizona consumers?

(c) for any identifiable risks, are the risks reduced or increased under a competitive retail regime?

(a) It is unlikely that PUHCA would simply be repealed without a transfer of some of the SEC's authority and functions under PUHCA to FERC or to the states. That being said, even a straight repeal of PUHCA would not affect the regulatory protections available to Arizona consumers for the simple reason that most Arizona electric utilities do not use the holding company structure. Those that do, such as APS, are currently exempt from all provisions of PUHCA except Section 9(a)(2). That section addresses the acquisition by APS' parent, PWCC, of additional "public utilities." Because PWCC's formation or acquisition of new subsidiaries is already addressed in state law provisions (A.A.C. R14-2-803), subject to any waivers granted by the Commission, PUHCA Section 9(a)(2)'s "protections" are largely superfluous.

(b) There would be little or no risk to Arizona consumers both for the reasons set forth above and also because the Commission would retain all existing authority over both of the PWCC entities—APS and APS Energy Services ("APSES")—selling at retail to Arizona consumers. Moreover, even if the repeal of PUHCA encouraged out-of-state holding companies to enter the Arizona market—which may be considered a plus from the standpoint of increased competition—their retail activities involving Arizona consumers would likewise become subject to the Commission's regulatory authority.

(c) The only identifiable "risks" are the expansion of existing Arizona holding companies into other areas and the expansion of out-of-state holding companies into Arizona, both of which can be addressed by the Commission in the absence of PUHCA. However, the potential for any affiliate abuse is clearly lessened by effective retail competition. Although Enron was not regulated under PUHCA, that company's collapse—as disastrous as it was for employees and Enron shareholders and as costly as it was for those who dealt with Enron on the wholesale level—is testament to the fact that a competitive market will eventually expose attempts by even its largest participant to engage in accounting irregularities or outright fraud.

2. What is the extent of the Commission's authority to protect retail consumers from any potential adverse consequences resulting from multistate companies operating in either wholesale or retail markets in the state?

If such companies operate only in the wholesale market, they would be exclusively regulated by FERC, except for the siting of generation and transmission facilities. The Commission can, of course, take actions at FERC against even these exclusively wholesale market participants that the Commission believes will protect retail consumers or Arizona buyers of power for retail consumers. To the extent that the Commission believes that transactions between jurisdictional Arizona electric utilities and such hypothetical "multi-state companies" may be imprudent and adversely affect retail customers, it can investigate such transactions in rate or other proceedings.

If such companies participate in the retail market, they subject themselves and their affiliates to Commission regulation, either directly as public service corporations or as affiliates under A.A.C. R14-2-801 to -806. The Commission also has limited constitutional authority over non-public service corporations pursuant to Article 15, Sections 4 and 5, of the Arizona Constitution as well as specified statutory authority (securities regulation, for example) pursuant to authority delegated to the Commission by the legislature under Article 15, Section 6 of the Arizona Constitution.

3. How would the existence of effective retail competition in Arizona affect your responses to Questions 1 and 2 above?

Effective retail competition in Arizona presupposes effective wholesale competition in the region. The existence of such competition reduces both the opportunity for consumer abuse and the need for active regulatory intervention. However, it would not reduce the Commission's legal authority to take actions to protect that market from abuses such as false or misleading advertising, and deceptive marketing practices.

4. What is the extent of any impact on effective federal or state regulation to protect Arizona wholesale and retail consumers, if a holding company is (a) registered or (b) "exempt" under PUHCA?

APS does not believe any Arizona electric utility is part of a registered holding company. If it were, however, the Commission would find some of its authority preempted by the SEC under PUHCA, as would FERC. Depending on which agency one believes is best positioned to protect Arizona consumers, being a registered holding company could actually reduce the level of protection afforded retail consumers in Arizona.

As regards exempt holding companies such as PWCC, both they and their retail electric affiliates in Arizona are subject to Commission authority as indicated in the response to Question No. 1. They are also subject to FERC authority, which is sometimes concurrent with that of the Commission and sometimes to the exclusion of state authority.

Exempt holding companies are also subject to some restrictions not imposed on registered holding companies concerning geographical diversification but no more so than that provided for under A.A.C. R14-2-801, *et seq*.

4.2 Questions for Retail Suppliers

5. Explain the retail supplier's corporate structure.

APS is an Arizona Subchapter C corporation. All of its outstanding common stock is owned free-and-clear by PWCC (also an Arizona corporation). APS has publicly-held debt, both secured and unsecured, but no preferred stock.

6. Identify all subsidiary companies and the businesses in which they are engaged.

The following companies are subsidiaries of APS:

- Axiom Power Solutions (inactive)
- Bixco, Inc. (inactive)
- APS Foundation, Inc. (charitable non-profit corporation)
- PWENEWCO Inc. (currently non-operating corporation formed to effectuate Commission-mandated transfer of generation assets to PWEC)

7. Identify all affiliate companies and the businesses in which they are engaged.

In addition to PWCC, which is a holding company and power marketing and trading company, the following companies are direct affiliates[11] of APS:

- APS Energy Services, Inc. (competitive ESP and energy service contractor)
- El Dorado Investment Company (venture capital)
- PWEC (generation company)
- SunCor Development Company (real estate)

APS Energy Services in turn has three subsidiaries, all involved in district cooling projects:

- Tucson District LLC
- Northwind Phoenix LLC
- Northwind Arizona Development LLC

PWEC created a subsidiary, GenWest LLC, to own its proposed generating facility in Nevada. PWEC and SunCor also jointly own an entity called APACS Holdings LLC, which in turn is a member of Copper Eagle Gas Storage, LLC, which is developing a gas storage site near Luke Air Force Base in conjunction with an affiliate of El Paso Natural Gas Co.

[11] Direct affiliates means companies that, like APS, are first-tier subsidiaries of PWCC.

In addition to these principal affiliates, there are various project-specific entities, such as limited liability corporations, limited partnerships and joint ventures, at both SunCor and El Dorado.

8. Identify each entity that owns or has control of 5% or more of an affiliate of the retail supplier, and describe the businesses in which that entity is engaged.

PWCC is a 100 percent owner of the four first-tier subsidiaries discussed above. APSES is the sole owner of its three affiliates, as is APS the sole owner of its subsidiaries. PWEC is the 100 percent owner of GenWest LLC and as noted above is a partial owner of Copper Eagle Gas Storage, LLC through APACS Holdings, LLC. SunCor and El Dorado have numerous investors in their various project-specific affiliates some of whom have interests greater than five percent in such project-specific entities. All the business activities of the SunCor and El Dorado subsidiaries are included in the overall PWCC financial results that are publicly available.

9. Describe the financial relationships among the various affiliates and subsidiaries, such as pledges of assets and encumbrances and contracts for services and goods.

As to PWCC, material financial relationships as described in the question, other than stock ownership, are as follows:

- Shared Services agreements with all first-tier subsidiaries for the provision of services such as legal, tax, and accounting.
- Financing to PWEC pending the transfer of APS' generation assets to PWEC (which transfer will allow PWEC to finance on its own).
- Guarantees for PWEC payments under letters of credit and for equipment and construction services for PWEC's generation projects.
- Similar financial and performance guarantees for APSES' activities in California and Arizona.
- Parental guarantees to El Dorado and SunCor.
- Performance guarantees to NAC Holding, Inc., a subsidiary of El Dorado generally involved in nuclear decommissioning matters.

PWCC Marketing and Trading provides the following services to affiliates:

- Gas procurement services for PWEC and APS.
- Scheduling services for APS and APSES.
- Procurement of purchased power and ancillary services for APS pursuant to a master purchase agreement on file with FERC (which agreement would be superceded by the proposed PPA).

APS' material financial relationships include the following:

- FERC-approved interconnection and transmission service agreements.
- Construction service agreements, as permitted by APS' Code of Conduct, with PWEC and APSES.
- Provides non-gas fuel procurement services for PWEC and PWCC.
- A reciprocal services agreement with APSES whereby APSES provides project management and marketing services to APS, and APS provides construction services to APSES, also in accordance with the APS Code of Conduct.

PWEC's material financial relationships are the following:

- Guarantee of certain of GenWest's obligations to the Southern Nevada Water Authority.
- An agreement with SunCor to eventually acquire SunCor's interest in Copper Eagle.

SunCor, as is customary in the real estate business, has the following material financial relationships:

- Performance and financial guarantees in conjunction with project-specific affiliates.
- Partner with PWEC in the Copper Eagle project.
- Customer of APS.

Additional information pertaining to the financial relationships can be found in the APS Affiliate Report pursuant to A.A.C. R14-2-805 and the PWCC 10-K. The former is already on file with the Commission. A copy of the latter for the most current year available (filed in March 2001) is provided at Appendix B.

10. Explain whether the retail supplier, or any affiliate or subsidiary of the retail supplier, is regulated by the Securities and Exchange Commission (SEC) as either an "exempt" or "registered" public utility holding.

PWCC is a "holding company" within the meaning of PUHCA. However, PWCC is exempt from all of the provisions of PUHCA, except Section 9(a)(2) of PUHCA, by virtue of PWCC's filing of an exemption statement on Form U-3A-2 with the SEC on or before March 1st of each year claiming an exemption as an "intrastate" holding company under Section 3(a)(1) of PUHCA and 17 CFR § 250.2(a). Section 9(a)(2) of PUHCA deals with the acquisition of the voting securities of additional public-utility company affiliates. Although PWCC engages in the marketing of power at wholesale and retail, these activities are not subject to regulation under PUHCA. PWCC is, however, subject to FERC regulation as a "public utility" under the Federal Power Act with respect to its wholesale power marketing activities. Neither APS or APSES, the retail suppliers, are a holding company, and therefore are not regulated by the SEC under PUHCA.

11. Identify any waivers or "no-action" letters the retail supplier, its affiliates, its subsidiaries, or other associated companies has received in the last 15 years from the SEC under PUHCA or the Investment Act of 1940 or from FERC under the Federal Power Act.

PUHCA:

Pinnacle West Capital Corporation (April 23, 1990): In this no-action letter, the SEC Staff confirmed that it would not recommend any enforcement action to the SEC under PUHCA as a result of PWCC's pledge of APS' common stock to secure PWCC's obligations to certain of its lenders (this pledge arrangement terminated several years ago, and PWCC now owns APS' outstanding common stock free and clear of any liens).

Investment Company Act of 1940:

PVNGS Funding Corp., Inc. - Release No. IC-15290 (Notice) (September 5, 1986)
PVNGS Funding Corp., Inc. - Release No. 15343 (SEC Order) (October 2, 1986)
Pursuant to the October 2, 1986 Order, the SEC granted an exemption from all provisions of the Investment Company of 1940 to PVNGS Funding Corp., Inc., an entity formed to assist APS in the 1986 sale-leaseback of a portion of APS' undivided interest in Unit 2 of the Palo Verde Nuclear Generating Station ("Palo Verde"). The September 5, 1986 Notice describes the factual and legal basis for the Order.

First Boston Corporation et al. (October 16, 1992) In this no-action letter, the SEC Staff confirmed that it would not recommend any enforcement action to the SEC under the Investment Company Act of 1940 if a "New Funding Corporation" (similar to PVNGS Funding Corp., Inc.) operated without registration as an investment company in reliance on the October 2, 1986 Order referenced in the immediately preceding paragraph (the New Funding Corporation was created to assist in the refinancing of the Palo Verde sale-leaseback debt issued by PVNGS Funding Corp., Inc. in 1986 and 1987; the refinancing took place in March, 1993, with The First Boston Corporation serving as the lead underwriter).

Federal Power Act:

Arizona Public Service Company, 79 FERC ¶ 61,022 (1997). On April 11, 1997, FERC granted APS' request for market-based rates and granted APS' request for waiver of certain reporting and filing requirements. Specifically, consistent with procedures FERC adopted in other market-based rate proceedings, APS may file umbrella service agreements for short-term transactions (one year or less) within 30 days of the date of commencement of short-term service, to be followed by quarterly transaction summaries of specific sales. For long-term transactions (longer than one year), APS must submit the actual individual service agreement for each transaction within 30 days of the date of commencement of service. On June 20, 2000, FERC accepted for filing APS' revised market-based rate tariff and code of conduct and granted APS the same waivers of certain

reporting and filing requirements. *Pinnacle West Capital Corporation, 91 FERC ¶ 61,290 (2000).*

Pinnacle West Capital Corporation, 91 FERC ¶ 61,290 (2000). On June 20, 2000, FERC accepted PWCC's market-based rate tariff and code of conduct and granted PWCC waivers of certain accounting and related reporting requirements. Specifically, FERC waived the requirements of Part 41 addressing adjustment of accounts and reports and certification of compliance with accounting records. The requirements of Part 101 have also been waived so PWCC need not keep its records according to the Uniform System of Accounts. The requirements of Part 141 also have been waived; which means that PWCC need not file FERC Form No. 1 or any of the other FERC forms. FERC also granted PWCC a waiver of the full requirements of Part 45 meaning that any person holding or who may hold an otherwise proscribed interlocking directorate involving PWCC shall instead file a sworn application providing the person's full name and business address and all jurisdictional interlocks, identifying the affected companies and the positions held by that person. In addition, PWCC was granted a waiver of the filing requirements of Subpart B (Documents to be Submitted with a Filing) and Subpart C (Other Filing Requirements) of Part 35 (Filing of Rate Schedules), except sections 35.12(a) (information to be included in filing letter), 35.13(b) (same), 35.15 (notice of termination) and 35.16 (notice of succession). Finally, FERC granted PWCC blanket approval of issuances of securities or assumptions of liabilities pursuant to Part 34 of the SEC's regulations. Additionally, PWCC was granted the same waivers with regard to the filing of service agreements and quarterly reports as APS.

Pinnacle West Energy Corporation, 92 FERC ¶ 61,248 (2000). On June 20, 2000, FERC accepted the market-based rate tariff and code of conduct of PWEC and granted PWEC the same waivers and authorizations as PWCC. Additionally, PWEC was granted the same waivers with regard to the filing of service agreements and quarterly reports as APS and PWCC.

APS Energy Services Company, Inc., 89 FERC ¶ 61,024 (1999) On October 13, 1999, FERC accepted the market-based rate tariff of APSES and granted APSES the following waivers and authorizations: (1) waiver of the accounting and related reporting requirements of Parts 41, 101, and 141 of the SEC's regulations; (2) permission to make abbreviated filings with regard to interlocking directorates under Part 45; and (3) waiver of the requirements of Subparts B and C of Part 35, except sections 35.12(a), 35.13(b), 35.15 and 35.16. Additionally, APSES was granted the same waivers with regard to the filing of service agreements and quarterly reports as APS, PWCC, and PWEC. On June 20, 2000, FERC accepted for filing APSES's revised market-based rate tariff and code of conduct and granted APSES the same waivers as PWCC. *Pinnacle West Capital Corporation, 91 FERC ¶ 61,290 (2000).*

12. Provide copies of filings to the SEC and FERC made by the retail supplier and any affiliates or subsidiaries in the last five years pursuant to the agency's administration of PUHCA.

Copies of the following exemption statements, and the filings further described below, are attached in Appendix C:

- *Form U-3A-2* *Filed February 28, 2001*
- *Form U-3A-2* *Filed February 29, 2000*
- *Form U-3A-2* *Filed March 1, 1999*
- *Form U-3A-2* *Filed February 27, 1998*
- *Form U-3A-2* *Filed February 28, 1997*

Pinnacle West Capital Corporation. On September 12, 2000, as amended on December 8, 2000, January 17, 2001, and April 27, 2001, PWCC filed an application (File No. 70-9745) with the SEC pursuant to Section 9(a)(2) of PUHCA requesting permission to establish a new public-utility company subsidiary in connection with the proposed corporate reorganization involving the relocation of certain generation assets from APS, PWCC's only then-existing public utility company subsidiary, to PWEC, another wholly-owned subsidiary of PWCC, and the operation of PWEC's West Phoenix Unit No. 4 as a non-EWG under the PUHCA. The SEC issued an order granting PWCC's request on April 27, 2001, and PWCC filed a post-effective amendment on May 11, 2001, certifying that the transactions contemplated in the application had taken place.

Pinnacle West Energy Corporation On *March* 28, 2001, PWEC filed an application for a determination that it was an EWG under Section 32 of PUHCA, but withdrew its application on May 2, 2001.

13. If the retail supplier is a subsidiary of a registered holding company, identify any SEC-approved contracts with affiliates or subsidiaries in the last 5 years.

This question does not apply because PWCC, APS' parent company, is not a "registered holding company." See the response to Question 10, above, for additional detail.

4.3 Divestiture or Corporate Separation

14. How would the divestiture or transfer of assets of vertically integrated utilities now serving Arizona affect the Commission's regulatory authority over the divested entities? What controls or limitations might the Commission place on divestiture or transfer of assets to limit any loss or authority over the divested assets?

If the transfer were to a non-affiliated party, the Commission would have no jurisdiction or authority over the acquiring entity so long as that entity refrained from

retail sales in Arizona. In the proposed 1998 Electric Competition Rules, the unconditional divestiture of generation to an unregulated and non-affiliated party was mandated. In the final version of the 1998 Rules to Commission permitted divestiture to an affiliate as an alternative to third-party divestiture. That requirement was retained in the 1999 Electric Competition Rules currently in effect. If the transfer were to such an affiliate, the affiliate would be subject to A.A.C. R14-2-801, *et seq*. If the affiliate were also selling power to the divesting utility, the Commission could review such power acquisitions, as is presently before the Commission in Docket No. E-01345A-01-0822.

In addition, although the commitment of divested resources to the service of APS was not a condition imposed on divestiture under the 1999 APS Settlement or by A.A.C. R14-2-1615, the use of a long-term buy-back power agreement such as the proposed purchase power agreement before the Commission in Docket No. E-01345A-01-0822 is a traditional means used by regulators to maintain such control and provides a means by which the divesting entity can transition to a fully competitive market while managing risk.

15. How would the divestiture or transfer of assets of vertically integrated utilities now serving Arizona affect federal jurisdiction under the FERC and the SEC over the divested entities?

The divestiture or transfer of assets in and of itself would have no effect on FERC or SEC jurisdiction over either the divesting entity or the entity to which such assets were divested. Obviously, the divesting entity's interest in the wholesale market may change from that of a combined buyer and seller to simply that of a buyer, but the jurisdictional forum would remain at FERC. Similarly, the SEC's jurisdiction is a function of the respective entities' business structure (i.e., holding company or no holding company, utility subsidiary or no utility subsidiary) or, aside from PUHCA, the manner of its financial structure (i.e., publicly held versus privately held securities)—neither of which is likely to be influenced in any manner by the suggested divestiture.

16. How would the potential effects of divestiture or transfer of assets on Commission authority differ under a competitive retail regime than under a monopoly regime?

From a legal standpoint, the effect on the Commission's authority (as discussed in response to Question No. 14) is unchanged as between a competitive retail regime and a monopoly regime. From a market structure standpoint, a monopoly retail regime would protect customers by providing them access to diverse generating assets priced using a cost-of-service based methodology. APS' proposed PPA would offer customers both the protections that are typically found in a "monopoly" regime and a transition to a more "competitive" regime.

17. How would a requirement that competitive services, such as generation services, be offered only through a separate corporate affiliate affect the Commission's regulatory authority and any risks identified in response to the questions above?

Of course, the Commission already has such a requirement under A.A.C. R14-2-1615. Moreover, the Code of Conduct imposed on APS pursuant to A.A.C. R14-2-1616 and Decision No. 62416 (April 3, 2000) also prohibits APS from providing Competitive Services, as defined therein. These provisions were designed to protect consumers from the risks of not divesting assets rather than the risks seemingly supposed by the question. The latter risks, to the extent thought more significant than the former, are addressed in the Company's response to Question No. 14. APS would also add that to the extent the receiving entity will itself engage in retail electric competition in Arizona—such as APS Energy Services—it would become directly regulated by the Commission in the same manner as other public service corporations.

18. For any risks resulting from a divestiture requirement or a requirement that competitive services be offered through separate affiliate, how might those risks be eliminated or reduced? Specifically –

a. What actions might the Arizona Commission take?

b. Are there actions that the Commission might encourage the FERC or the SEC to take to maintain adequate oversight for the protection of ratepayers?

(a) If that separate affiliate will be providing retail electric services in Arizona, it will be directly regulated by the Commission, and the Commission can take such lawful actions regarding such affiliate as are necessary to protect consumers. If generation is being divested to an affiliate willing to enter into a cost-based buy-back agreement, this effectively insulates customers from the effects (if any) of divestiture. If the authority to divest is unqualified, the Commission should encourage the divesting utility to consider this option on a voluntary basis as being a prudent resource acquisition strategy. This is precisely what APS did with respect to PWCC and PWEC and what the Company has proposed in Docket No. E-01345A-01-0822.

(b) As stated in response to Question No. 15, the fact of divestiture does not affect FERC or SEC jurisdiction. However, and aside from the issue of divestiture, the Commission should encourage FERC actions that promote open competitive wholesale electric markets. Such markets will benefit Arizona consumers irrespective of whether retail electric competition does or does not mature in this state. Likewise, the Commission should encourage the SEC to promote and those utilities under its (and the Commission's) jurisdiction to follow appropriate accounting practices that accurately reflect the firm's current value and profitability.

SECTION V
COMMISSIONER IRVIN'S FEBRUARY 7, 2002 LETTER

5.1 AISA and FERC Jurisdiction

1. Please address whether Arizona's Constitution prohibits the Commission from giving up any authority with respect to the pricing of services by public service corporations which occur solely within the state.

The Arizona Constitution does not specifically address the issue of surrendering Commission authority to regulate services provided by public service corporations within Arizona. This is especially true when it comes to the allocation of jurisdictional powers between the Commission and federal regulatory agencies such as FERC. However, to the extent that the Commission's pricing and ratemaking authority under the Arizona Constitution is preempted by federal law, the Commission must defer to FERC pursuant to the "supremacy clause" of the U.S. Constitution which controls over any arguably conflicting portion of the Arizona Constitution. Therefore, the Arizona Constitution does not prohibit the Commission from giving up authority to federal agencies (including FERC) when its pricing authority is preempted by FERC's jurisdiction over interstate transmission and wholesale power, even if such pricing occurs solely within Arizona's borders.

2. Should Arizona be willing to let the federal government take over pricing jurisdiction (market-based rates) for all retail transactions which occur in the state, or is this an inevitable (and proper) result of opening retail markets to competition?

Though FERC has asserted that it is looking to expand its jurisdictional role over certain aspects of retail market transactions in a deregulated environment, a move to retail competition will not result in the federal government taking over all aspects of ratemaking and pricing within Arizona.

To the contrary, under current law, FERC will, at most, exercise exclusive jurisdiction primarily with respect to the interstate transmission component of unbundled services, something which FERC claims has always been under the jurisdiction of FERC pursuant to the Federal Power Act. Also, when electricity services are unbundled and transmission services are made available as a separate product, FERC has asserted exclusive authority over transmission service pricing for all transactions, whether unbundled, direct access or bundled standard offer. Such assertion is currently before the courts. However, the Commission will continue to retain and exercise exclusive jurisdiction with respect to all other aspects of pricing, including retail sales, distribution services, metering, billing, etc.

There is currently some proposed legislation pending before Congress that aims to expand FERC's market-based pricing authority. For example, one piece of legislation aims to give FERC authority to charge end users for federally mandated environmental

programs. However, given the precarious politics surrounding enactment of energy legislation before Congress, it is not clear that any of these proposals will pass any time in the near future. Therefore, Arizona's adoption of a system where electricity services are unbundled and generation services are divested will not force the Commission to cede all pricing authority to FERC.

3. Can Arizona's UDCs modify their tariffs with the FERC to conform with AISA protocols so that retail transactions can still take place without the AISA? How many times has the AISA been used to resolve disputes over transmission issues?

Arizona UDCs can modify their tariffs with FERC to conform substantially with the AISA protocols so that retail transactions can still take place without the AISA. To date, the AISA has never resolved disputes over transmission issues.

5.2 Markets

1. If the majority of market participants intend to market electricity only to industrial, large commercial and load serving ESPs entities, should retail markets be limited by load size to allow those entities with true bargaining power to negotiate Direct Access?

Ironically, this was an APS proposal early in the restructuring investigation conducted by the Commission. However, this proposed limitation was viewed, and likely would continue to be viewed, as discriminatory. Therefore, APS would not recommend limiting the ability of any Arizona consumer to select Direct Access if there is an ESP willing to serve them.

2. What will be a UDC's primary functions in a competitive market?

As set forth in the current Electric Competition Rules, a UDC provides Non-Competitive Electric Services such as distribution and bundled Standard Offer. In the latter role, the UDC would seek reliable and reasonably-priced sources of power for Standard Offer customers and must be allowed timely recovery of associated costs.

3. Is it important to first establish functional wholesale markets before creating robust retail markets in electric generation? If so, why? If not, why?

Yes, but fortunately the West already has a functional wholesale market. That market is functional but very volatile and unpredictable. If it were not functional—such as if there were insufficient participants with insufficient resources or if there was not sufficient market liquidity and transparency—it would be unlikely that ESPs could acquire sufficient quantities of reasonable priced power and would be unable to effectively hedge market volatility. Without a sufficient number of viable ESPs, retail competition can never be robust. The proposed PPA will provide a safety net from the volatility of the wholesale market while both permitting APS customers to opt for Direct

Access if practical for such customer and provides a gradual phase-in of competitive market supplies for Standard Offer customers.

4. ***When price caps are lifted for the majority of Arizona consumers, what assurances do we have that volatility in the market (for both natural gas and electricity) will not result in unstable or inflated rates? Will the generation price of electricity fluctuate with the price of natural gas?***

The best assurance for Standard Offer customers would be the ability to lock in cost-based prices for a fuel-diverse portfolio of generating assets as is called for under APS' proposed PPA. While market generation prices for all generation (not just gas-fired generation) will fluctuate in tandem with the price of natural gas, the energy component of power under the APS proposed purchase power agreement is largely driven by coal and nuclear fuel prices under long-term supply agreements. These prices are largely immune from swings in the price of natural gas. Finally, the Commission should support jurisdictional utilities that take prudent advantage of financial and other commodity price hedging strategies to reduce the price volatility of both natural gas and purchased power. This could be done by assuring utilities that financial and commodity hedges would be treated as a fuel or purchased power cost and recovered in rates accordingly.

5. ***Should there be a provision added to R14-2-1606(B) which would allow/limit a UDC to contract for wholesale power in three or five year intervals? What would be a proper length for contracts?***

No. There is no purpose served by further limiting the UDC's procurement options other than to make Standard Offer Service more expensive and more volatile, discourage new generation investment, and make resource planning less efficient. The proper length for such contracts is whatever length is consistent with a prudent and (for Standard Offer) conservative procurement strategy. Among the factors to be considered are:

- reliability of supply,
- diversity of supply,
- creditworthiness of counter-party
- overall attractiveness of price,
- price level, stability and predictability, and
- availability of existing transmission infrastructure.

6. ***What are the real benefits to residential consumers and small businesses in retail competition, other than consumer choice? Will IPPs market their power directly to retail customers, or are their efforts mainly focused on selling power to wholesale customers?***

Choice is itself a considerable benefit in the minds of many consumers. Moreover, the mere existence of consumer choice places competitive pressure on incumbent suppliers of standard offer service to be more cost-efficient and consumer-oriented.

Indeed, APS' prices were already declining prior to 1996, thus indicating that even the threat of competition is a powerful incentive for such efficiency.

APS doubts that any merchant generator will directly market generation to retail customers. For one thing, to do so would make them subject to Commission jurisdiction and would not allow them to be considered Exempt Wholesale Generators. Also, most merchant generators are not set up to engage in the direct marketing of their output.

7. Currently, is residential choice a real option? If not now, when?

Not at the present time. The wholesale market must either become less volatile or ESPs must be able to garner enough non-residential business to allow them to hedge a volatile wholesale market to the point where they can offer residential customers the price stability and predictability they desire. Also, ESPs must find ways of bringing down transactional costs for such customers.

8. What provisions, if any, are necessary to effectuate a gradual replacement of those existing plants in Arizona which are older, more polluting and less efficient than the new combined cycle plants currently being built?

APS does not believe that replacement of all existing coal-burning plants, let alone existing natural gas or nuclear plants, in Arizona is a desirable goal. Instead, APS believes that the Commission should pursue an energy policy that recognizes the value of older plants in Arizona instead of prematurely decommissioning them and replacing them with combined cycle plants. There are several reasons why retaining existing plants and ensuring that they run efficiently and cleanly makes sense, from both an economical and environmental standpoint.

First, retaining coal-burning and nuclear units ensures that Arizona will continue to rely on diverse fuel sources. The events that unfolded in California and the unpredictable volatility associated with natural gas prices strongly suggest that increased reliance on gas-fired units eventually leads to increased costs for retail customers and substantially reduces overall system reliability.

Second, APS' coal-burning units employ clean and efficient technologies to ensure minimal environmental and pollution impact. More specifically, all of APS' coal units burn low sulfur coal and operate below applicable emission limitations.

Third, in assessing the environmental impact of coal burning generators, the Commission should consider where these plants are located. All of APS' coal plants are located in low population density areas. Because of their remote location, the environmental impact of these coal-burning units is generally not aggregated with the effects of other polluting sources in the area, thus significantly minimizing any negative environmental effects on the surrounding areas.

Finally, many of the coal-burning units are located on Navajo and Hopi reservations in northeastern Arizona. Replacement of these units with combined cycle plants would cause significant economic disruption to these communities and their surrounding areas.

Today, coal remains the most abundant energy source in Arizona. APS believes that it is possible to pursue a balanced energy policy that integrates use of existing coal-burning units as well as nuclear and gas-fired units in an economically effective and environmentally responsible manner. Furthermore, a policy that allows the continued operation of these older units avoids the need to reimburse APS and other utilities for sunk costs and investments associated with the construction of these plants.

9. What are the long-term effects of divestiture for APS? How does the Commission guard against a PG&E situation, where the distribution company declares bankruptcy after profits have flowed to its parent holding company?

Getting APS out of the electric generation business (as the Electric Competition Rules require) will permit it to focus on Non-Competitive Electric Service, remove the financial strain and financial risk inherent in building new generation, and permit competitive suppliers to compete free of the perceived threat posed by an incumbent owner of generation. On the other hand, divesting generation can reduce the ability of the UDC to hedge against market price volatility unless the generation is replaced to a great extent by a long-term agreement or agreements that provide the same hedge without the disadvantages associated with continued UDC ownership of generation.

APS is unaware of whether all or a portion of PG&E's profits were paid as dividends to its parent holding company, as supposed in the question, although APS would note that there is nothing unusual or illegal about reasonable dividends to a company's shareholders. The PG&E bankruptcy was caused by the utility being placed in a "price squeeze" between fixed retail rates and exploding wholesale costs. There is considerable debate as to the cause for these high wholesale prices, but to APS' knowledge, no one has accused PG&E of somehow manipulating the wholesale market. The Commission can best avoid such a situation involving a UDC under its jurisdiction by promoting a sound and predictable regulatory environment, encouraging UDCs to lock in reasonable and stable wholesale prices, and to thereafter allow timely recovery in retail rates of these and other legitimate purchases by the UDC on behalf of its Standard Offer customers as called for under the 1999 APS Settlement Agreement.

APPENDICES

Appendix A:

Joint Committee on Taxation, Description of S. ____, "Energy Tax Incentives Act of 2002" (JCX-2-02)

Appendix B:

Pinnacle West Capital Corporation 10-K (March 2001)

Appendix C: Filings Related to the Public Utility Holding Company Act

1. Form U-3A-2: Statement by Holding Company Claiming Exemption Under Rule U-3A-2 from the Provisions of PUHCA (February 28, 2001)

2. Form U-3A-2: Statement by Holding Company Claiming Exemption Under Rule U-3A-2 from the Provisions of PUHCA (February 29, 2000)

3. Form U-3A-2: Statement by Holding Company Claiming Exemption Under Rule U-3A-2 from the Provisions of PUHCA (March 1, 1999)

4. Form U-3A-2: Statement by Holding Company Claiming Exemption Under Rule U-3A-2 from the Provisions of PUHCA (February 27, 1998)

5. Form U-3A-2: Statement by Holding Company Claiming Exemption Under Rule U-3A-2 from the Provisions of PUHCA (February 28, 1997)

6. Application of APS Energy Services for Order Approving Market-Based Rates (August 19, 1999)

7. FERC Order re APS Energy Services Application for Order Approving Market-Based Rates (October 13, 1999)

8. FERC Order Conditionally Accepting for Filing Proposed Market-Based Tariff and Code of Conduct, and Revised Market-Based Rate Tariff and Code of Conduct (June 20, 2000)

9. Application of Pinnacle West Capital Corporation for Order Approving Market-Based Rates, Waiving Regulations, and Granting Blanket Approvals; and Request of Arizona Public Service Company and APS Energy Services for Modification of Tariffs, Codes of Conduct and APS Rate Schedules and Service Agreements (April 21, 2000)

10. Application of Pinnacle West Energy Corporation for Order Approving Market-Based Rates (July 28, 2000)

11. FERC Order Accepting for Filing Proposed Market-Based Rate Tariff Filed by Pinnacle West Energy Corporation (September 26, 2000)

12. Arizona Public Service's Application for Order Approving Market-Based Rates (February 12, 1997)

13. FERC Order Conditionally Accepting for Filing Proposed Market-Based Rates (April 11, 1997)

14. Application of Pinnacle West Energy Corporation for Determination of Exempt Wholesale Generator Status (March 28, 2001)

15. Amended and Supplemental Application of Pinnacle West Energy Corporation for Determination of Exempt Wholesale Generator Status (April 27, 2001)

16. Pinnacle West Energy Corporation's Notice of Withdrawal of its Application for Determination of Exempt Wholesale Generator Status (May 2, 2001)

17. Form U-1—Application Under the Public Utility Holding Company Act of 1935 (September 12, 2000)

18. Amendment No. 1 to Form U-1—Application Under the Public Utility Holding Company Act of 1935 (December 8, 2000)

19. Amendment No. 2 to Form U-1—Application Under the Public Utility Holding Company Act of 1935 (January 17, 2001)

20. Amendment No. 3 to Form U-1—Application Under the Public Utility Holding Company Act of 1935 (April 27, 2001)

21. Amendment No. 4 to Form U-1—Application Under the Public Utility Holding Company Act of 1935 (May 11, 2001)

1141507

A

DESCRIPTION OF S. _____
"ENERGY TAX INCENTIVES ACT OF 2002"

Scheduled for Markup
by the
Senate Finance Committee
on February 13, 2002

Prepared by
the Staff of the
JOINT COMMTTEE ON TAXATION

February 11, 2002
JCX-2-02

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INTRODUCTION

The Senate Committee on Finance has scheduled a markup on February 13, 2002, of S. _____ "Energy Tax Incentives Act of 2002." This document,[1] prepared by the staff of the Joint Committee on Taxation, provides a description of the "Energy Tax Incentives Act of 2002."

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[1] This document may be cited as follows: Joint Committee on Taxation, *Description of S. _____, "Energy Tax Incentives Act of 2002"* (JCX-2-02), February 11, 2002.

I. RENEWABLE ENERGY

A. Extension and Modification of the Section 45 Electricity Production Credit

Present Law

An income tax credit is allowed for the production of electricity from either qualified wind energy, qualified "closed-loop" biomass, or qualified poultry waste facilities (sec. 45). The amount of the credit is 1.5 cents per kilowatt hour (indexed for inflation) of electricity produced. The amount of the credit was 1.7 cents per kilowatt hour for 2001. The credit is reduced for grants, tax-exempt bonds, subsidized energy financing, and other credits.

The credit applies to electricity produced by a wind energy facility placed in service after December 31, 1993, and before January 1, 2002, to electricity produced by a closed-loop biomass facility placed in service after December 31, 1992, and before January 1, 2002, and to a poultry waste facility placed in service after December 31, 1999, and before January 1, 2002. The credit is allowable for production during the 10-year period after a facility is originally placed in service. In order to claim the credit, a taxpayer must own the facility and sell the electricity produced by the facility to an unrelated party. In the case of a poultry waste facility, the taxpayer may claim the credit as a lessee/operator of a facility owned by a governmental unit.

Closed-loop biomass is plant matter, where the plants are grown for the sole purpose of being used to generate electricity. It does not include waste materials (including, but not limited to, scrap wood, manure, and municipal or agricultural waste). The credit also is not available to taxpayers who use standing timber to produce electricity. Poultry waste means poultry manure and litter, including wood shavings, straw, rice hulls, and other bedding material for the disposition of manure.

The credit for electricity produced from wind, closed-loop biomass, or poultry waste is a component of the general business credit (sec. 38(b)(8)). The credit, when combined with all other components of the general business credit, generally may not exceed for any taxable year the excess of the taxpayer's net income tax over the greater of (1) 25 percent of net regular tax liability above $25,000, or (2) the tentative minimum tax. For credits arising in taxable years beginning after December 31, 1997, an unused general business credit generally may be carried back one year and carried forward 20 years (sec. 39). To coordinate the carryback with the period of application for this credit, the credit for electricity produced from closed-loop biomass facilities may not be carried back to a tax year ending before 1993 and the credit for electricity produced from wind energy may not be carried back to a tax year ending before 1994 (sec. 39).

Description of Proposal

The proposal would extend the placed in service date for wind facilities, closed-loop biomass facilities, and poultry waste facilities to facilities placed in service after December 31, 1993 (December 31, 1992 in the case of closed-loop biomass facilities and December 31, 1999 in the case of poultry waste facilities) and before January 1, 2007.

The proposal also would define three new qualifying energy resources: open-loop biomass, swine and bovine waste nutrients, and geothermal energy. Open-loop biomass would

be defined as any solid, nonhazardous, cellulosic waste material which is segregated from other waste materials and which is derived from any of forest-related resources, solid wood waste materials, or agricultural sources. Eligible forest-related resources would be defined as mill residues, precommercial thinnings, slash, and brush, but not including old-growth timber. Solid wood waste materials would include waste pallets, crates, dunnage, manufacturing and construction wood wastes (other than pressure-treated, chemically-treated, or painted wood wastes), and landscape or right-of-way tree trimmings. Agricultural sources would include orchard tree crops, vineyard, grain, legumes, sugar, and other crop by-products or residues. However, qualifying open-loop biomass would not include municipal solid waste (garbage), gas derived from biodegradation of solid waste, or paper that is commonly recycled. Swine and bovine waste nutrients would be defined as swine and bovine manure and litter, including bedding material for the disposition of manure. Geothermal energy would be defined as energy derived from a geothermal deposit which is a geothermal reservoir consisting of natural heat which is stored in rocks or in an aqueous liquid or vapor (whether or not under pressure).

Qualifying open-loop biomass facilities would be facilities using open-loop biomass to produce electricity that are placed in service prior to January 1, 2005. Qualifying swine and bovine waste nutrient facilities would be facilities using swine and bovine waste nutrients to produce electricity that are placed in service after the date of enactment and before January 1, 2007. Qualifying geothermal energy facilities would be facilities using geothermal deposits to produce electricity that are placed in service after the date of enactment and before January 1, 2007.

In the case of qualifying open-loop biomass facilities, taxpayers would be able to claim the otherwise allowable credit for a three-year period. For facilities placed in service after the date of enactment, the three-year period would commence when the facility is placed in service. In the case of open-loop biomass facilities originally placed in service before the date of enactment, the three-year period would commence after December 31, 2002 and the otherwise allowable 1.5 cent-per-kilowatt-hour credit (adjusted for inflation) would be reduced to 1.0 cent-per-kilowatt-hour credit (adjusted for inflation). In the case of qualifying geothermal energy facilities, taxpayers would be able to claim the otherwise allowable credit for the five-year period commencing when the facility is placed service.

The proposal would modify present law to provide that qualifying closed-loop biomass facilities include any facility originally placed in service before December 31, 1992 and modified to use closed-loop biomass to co-fire with coal before January 1, 2007.

In the case of qualifying open-loop biomass facilities and qualifying closed-loop biomass facilities modified to use closed-loop biomass to co-fire with coal, the proposal would permit a lessee operator to claim the credit in lieu of the owner of the facilities.

The proposal would provide that certain persons (public utilities, electric cooperatives, rural electric cooperatives, and Indian tribes) could sell, trade, or assign to any taxpayer any credits that would otherwise be allowable to that person, if that person were a taxpayer, for production of electricity from a qualified facility owned by such person. In addition, any credits that would otherwise be allowable to such person may be applied as a prepayment to certain loans or obligations undertaken by such person under the Rural Electrification Act of 1936.

Lastly, the proposal would repeal the present-law reduction in allowable credit for facilities financed with tax-exempt bonds or with certain loans received under the Rural Electrification Act of 1936.

Effective Date

The proposal generally would be effective for electricity sold from qualifying facilities after the date of enactment. For electricity produced from qualifying open-loop biomass facilities originally placed in service prior to the date of enactment, the proposal would be effective January 1, 2003.

II. ALTERNATIVE VEHICLES AND FUEL INCENTIVES

A. Modifications and Extensions of Provisions Relating to Electric Vehicles, Clean-Fuel Vehicles, and Clean-Fuel Vehicle Refueling Property

Present Law

A 10-percent tax credit is provided for the cost of a qualified electric vehicle, up to a maximum credit of $4,000 (sec. 30). A qualified electric vehicle is a motor vehicle that is powered primarily by an electric motor drawing current from rechargeable batteries, fuel cells, or other portable sources of electrical current, the original use of which commences with the taxpayer, and that is acquired for the use by the taxpayer and not for resale. The full amount of the credit is available for purchases prior to 2002. The credit phases down in the years 2002 through 2004, and is unavailable for purchases after December 31, 2004. There is no carry forward or carryback of the credit for electric vehicles.

Certain costs of qualified clean-fuel vehicle property and clean-fuel vehicle refueling property may be expensed and deducted when such property is placed in service (sec. 179A). Qualified clean-fuel vehicle property includes motor vehicles that use certain clean-burning fuels (natural gas, liquefied natural gas, liquefied petroleum gas, hydrogen, electricity and any other fuel at least 85 percent of which is methanol, ethanol, or any other alcohol or ether). The maximum amount of the deduction is $50,000 for a truck or van with a gross vehicle weight over 26,000 pounds or a bus with seating capacities of at least 20 adults; $5,000 in the case of a truck or van with a gross vehicle weight between 10,000 and 26,000 pounds; and $2,000 in the case of any other motor vehicle. Qualified electric vehicles do not qualify for the clean-fuel vehicle deduction.

Clean-fuel vehicle refueling property comprises property for the storage or dispensing of a clean-burning fuel, if the storage or dispensing is the point at which the fuel is delivered into the fuel tank of a motor vehicle. Clean-fuel vehicle refueling property also includes property for the recharging of electric vehicles, but only if the property is located at a point where the electric vehicle is recharged. Up to $100,000 of such property at each location owned by the taxpayer may be expensed with respect to that location.

The deduction phases down in the years 2002 through 2004, and is unavailable for purchases after December 31, 2004.

Description of Proposal

Alternative motor vehicle credits

The proposal would provide a credit to the taxpayer for the purchase of a new qualified fuel cell motor vehicle, a new qualified alternative fuel motor vehicle, and a new qualified hybrid motor vehicle. The taxpayer would be able to carry forward unused credits for 20 years or carry unused credits back for three years (but not carried back to taxable years beginning before the January 1, 2003). In the case of property purchased by tax-exempt persons, the seller may claim

the credit. In addition to the specifications described below, a qualifying vehicle would have to meet certain emissions standards.

Fuel cell motor vehicles

The credit for the purchase of new qualified fuel cell motor vehicles generally ranges between $4,000 and $40,000 depending upon the weight class of the vehicle. For automobiles and light trucks, the otherwise allowable credit amount ($4,000) is increased by an amount from $1,000 to $4,000 depending upon the vehicle's fuel efficiency compared to a stated standard. Credit may not be claimed for qualified fuel cell motor vehicles purchased after December 31, 2011. The taxpayer's basis in the property is reduced by the amount of credit claimed.

Hybrid motor vehicles

The credit for the purchase of a new qualified hybrid motor vehicle generally ranges from $250 to $10,000 depending upon the weight of the vehicle and the maximum power available from the vehicle's battery system. For automobiles and light trucks, the otherwise allowable credit amount ($250 to $1,000) is increased by an amount from $1,000 to $3,500 depending upon the vehicle's fuel efficiency. For heavy duty hybrid motor vehicles, the otherwise allowable credit ($1,000 to $10,000) is increased depending upon the vehicle's weight and provided the vehicle meets certain 2007 (and beyond) emissions standards. The amount of credit is increased by between $3,000 and $12,000 for vehicles placed in service in 2003, is increased by between $2,500 and $10,000 for vehicles placed in service in 2004, is increased by between $2,000 and $8,000 for vehicles placed in service in 2005, and is increased by between $1,500 and $6,000 for vehicles placed in service in 2006. Credit may not be claimed for qualified hybrid motor vehicles purchased after December 31, 2006. The taxpayer's basis in the property is reduced by the amount of credit claimed.

Alternative fuel motor vehicles

The credit for the purchase of a new alternative fuel motor vehicle equals 40 percent of the incremental cost of such vehicle, plus an additional 30 percent if the vehicle meets certain emissions standards. For computation of the credit, incremental costs of the vehicle may not exceed between $5,000 and $40,000 depending upon the weight of the vehicle. For this purpose, incremental cost generally would be defined as the amount of the increase of the cost of such a vehicle compared to the cost of a comparable gasoline or diesel model. Qualifying alternative fuels are compressed natural gas, liquefied natural gas, liquefied petroleum gas, hydrogen, and any liquid mixture consisting of at least 85 percent methanol.

Certain mixed-fuel vehicles also could claim the alternative fuel motor vehicle credit, at a reduced rate. A mixed-fuel vehicle is a vehicle with gross weight of seven tons or more and is certified by the manufacturer as being able to operate on a combination of alternative fuel and a petroleum-based fuel. A qualifying mixed-fuel vehicle must use at least 75 percent alternative fuel (a "75/25 mixed-fuel vehicle") or 90 percent alternative fuel (a "90/10 mixed-fuel vehicle") and is incapable of operating on a mixture containing less than 75 percent alternative fuel in the case of a 75/25 vehicle (less than 90 percent alternative fuel in the case of a 90/10 vehicle. A taxpayer purchasing a 75/25 mixed-fuel vehicle may claim 70 percent of the otherwise allowable

credit. A taxpayer purchasing a 90/10 mixed-fuel vehicle may claim 90 percent of the otherwise allowable credit.

Credit may not be claimed for qualified alternative fuel motor vehicles purchased after December 31, 2006. The taxpayer's basis in the property is reduced by the amount of credit claimed.

Modification of credit for qualified electric vehicles

The proposal would modify the present-law credit for electric vehicles to provide that the credit for qualifying vehicles generally ranges between $3,500 and $40,000 depending upon the weight of the vehicle and, for certain vehicles, the driving range of the vehicle. In the case of property purchased by tax-exempt persons, the seller may claim the credit. The taxpayer would be ineligible for the deduction allowable under present-law section 179A for a qualified battery electric vehicle on which a credit is allowable. The proposal also would extend the expiration date of the credit from December 31, 2004 to December 31, 2006 and would repeal the phaseout schedule of present law. The taxpayer would be able to carry forward unused credits for 20 years or carry unused credits back for three years (but not carried back to taxable years beginning before the January 1, 2003).

Extension of present-law section 179A

The proposal would extend the deduction for costs of qualified clean-fuel vehicle property and clean-fuel vehicle refueling property through December 31, 2006. The phase-down of present law for clean fuel vehicles would be modified such that the taxpayer may claim 75 percent of the otherwise allowable deduction in 2003 and 2004, 50 percent of the otherwise allowable deduction in 2005, and 75 percent of the otherwise allowable deduction in 2006.

Credit for installation of alternative fueling stations

The proposal would permit taxpayers to claim a 50-percent credit for the cost of installing clean-fuel vehicle refueling property to be used in a trade or business of the taxpayer or installed at the principal residence of the taxpayer. In the case of retail clean-fuel vehicle refueling property the allowable credit could not exceed $30,000. In the case of residential clean-fuel vehicle refueling property the allowable credit could not exceed $1,000. The taxpayer's basis in the property would be reduced by the amount of the credit and the taxpayer could not claim deductions under section 179A with respect to property for which the credit is claimed. In the case of refueling property installed on property owned or used by a tax-exempt person, the taxpayer that installs the property may claim the credit. To be eligible for the credit, the property must be placed in service before January 1, 2007. Taxpayers would be able to carry forward unused credits for 20 years.

Credit for retail sale of alternative fuels

The proposal would permit taxpayers to claim a credit equal to the gasoline gallon equivalent of 30 cents per gallon of alternative fuel sold in 2003, 40 cents per gallon in 2004, and 50 cents per gallon thereafter. Qualifying alternative fuels are compressed natural gas, liquefied natural gas, liquefied petroleum gas, hydrogen, any liquid mixture consisting of at least 85

percent methanol, and any liquid mixture consisting of at least 85 percent ethanol. The gasoline gallon equivalency of any alternative fuel is determined by reference to the British thermal unit content of the alternative fuel compared to a gallon of gasoline. The credit may be claimed for sales prior to January 1, 2007. The credit would be part of the general business credit.

Effective Date

The proposals relating to the credit for new fuel cell motor vehicles, hybrid motor vehicles, and alternative fuel motor vehicles, the credit for battery electric vehicles, the credit for alternative fuel vehicle refueling property, and deductions clean fuel vehicles and clean fuel refueling property would apply to property placed in service after December 31, 2002, in taxable years ending after December 31, 2002. The credit for retail sales of alternative fuels would apply to sales of fuels after December 31, 2002, in taxable years ending after December 31, 2002.

B. Modifications to Small Producer Ethanol Credit

Present Law

Small producer credit

Present law provides several tax benefits for ethanol and methanol produced from renewable sources (e.g., biomass) that are used as a motor fuel or that are blended with other fuels (e.g., gasoline) for such a use. In the case of ethanol, a separate 10-cents-per-gallon credit for small producers, defined generally as persons whose production does not exceed 15 million gallons per year and whose production capacity does not exceed 30 million gallons per year. The alcohol fuels tax credits are includible in income. This credit, like tax credits generally, may not be used to offset alternative minimum tax liability. The credit is a treated as a general business credit, subject to the ordering rules and carryforward/carryback rules that apply to business credits generally. The alcohol fuels tax credit is scheduled to expire after December 31, 2007.

Taxation of cooperatives and their patrons

Under present law, cooperatives in essence are treated as pass-through entities in that the cooperative is not subject to corporate income tax to the extent the cooperative timely pays patronage dividends. Under present law (sec. 38(d)(4)), the only excess credits that may be flowed-through to cooperative patrons are the rehabilitation credit (sec. 47), the energy property credit (sec. 48(a)), and the reforestation credit (sec. 48(b)).

Description of Proposal

The proposal would make several modifications to the rules governing the small producer ethanol credit. First, the proposal would liberalize the definition of an eligible small producer to include persons whose production capacity does not exceed 60 million gallons. Second, the proposal would allow cooperatives to elect to pass-through the small ethanol producer credits to its patrons. The credit allowed to a particular patron would be that proportion of the credit that the cooperative elects to pass-through for that year as the amount of patronage of that patron for that year bears to total patronage of all patrons for that year.

Third, the proposal would repeal the rule that includes the small producer credit in income of taxpayers claiming it and would liberalize the ordering and carryforward/carryback rules for the small producer ethanol credit. Fourth, the proposal would allow the small producer credit to be claimed against the alternative minimum tax. Finally, the proposal would provide that the small producer ethanol credit would not be treated as derived from a passive activity under the Code rules restricting credits and deductions attributable to such activities.

Effective Date

The proposal would be effective for taxable years beginning after date of enactment.

C. Transfer Full Amount of Excise Tax Imposed on Gasohol to the Highway Trust Fund

Present Law

An 18.4 cents-per-gallon excise tax is imposed on gasoline. The tax is imposed when the fuel is removed from a refinery unless the removal is to a bulk transportation facility (e.g., removal by pipeline or barge to a registered terminal). In the case gasoline removed in bulk by registered parties, tax is imposed when the gasoline is removed from the terminal facility, typically by truck (i.e., "breaks bulk"). If gasoline is sold to an unregistered party before it is removed from a terminal, tax is imposed on that sale. When the gasoline subsequently breaks bulk, a second tax is imposed. The payor of the second tax may file a refund claim if it can prove payment of the first tax. The party liable for payment of the gasoline excise tax is called a "position holder," defined as the owner of record inside the refinery or terminal facility.

A 53-cents-per-gallon income tax credit is allowed for ethanol used as a motor fuel (the "alcohol fuels credit"). The benefit of the alcohol fuels tax credit may be claimed as a reduction in excise tax payments when the ethanol is blended with gasoline ("gasohol"). The reduction is based on the amount of ethanol contained in the gasohol. The excise tax benefits apply to gasohol blends of 90 percent gasoline/10 percent ethanol, 92.3 percent gasoline/7.7 percent ethanol, or 94.3 percent gasoline/5.7 percent ethanol. The income tax credit is based on the amount of alcohol contained in the blended fuel.

In general, 18.3 cents per gallon of the gasoline excise tax is deposited in the Highway Trust Fund and 0.1 cent per gallon is deposited in the Leaking Underground Storage Tank Trust Fund (the "LUST" rate). In the case of gasohol with respect to which a reduced excise tax is paid, 2.5 cents per gallon of the reduced tax is retained in the General Fund. The balance of the reduced rate (less the LUST rate) is deposited in the Highway Trust Fund.

Description of Proposal

The proposal would transfer the 2.5 cents per gallon of excise tax on gasohol that currently is retained in the General Fund to the Highway Trust Fund.

Effective Date

The proposal would be effective taxes imposed after September 31, 2003.

D. Modify Income Tax and Excise Tax Rules Governing Treatment of ETBE

Present Law

An 18.4 cents-per-gallon excise tax is imposed on gasoline. The tax is imposed when the fuel is removed from a refinery unless the removal is to a bulk transportation facility (e.g., removal by pipeline or barge to a registered terminal). In the case gasoline removed in bulk by registered parties, tax is imposed when the gasoline is removed from the terminal facility, typically by truck (i.e., "breaks bulk"). If gasoline is sold to an unregistered party before it is removed from a terminal, tax is imposed on that sale. When the gasoline subsequently breaks bulk, a second tax is imposed. The payor of the second tax may file a refund claim if it can prove payment of the first tax. The party liable for payment of the gasoline excise tax is called a "position holder," defined as the owner of record inside the refinery or terminal facility.

A 53-cents-per-gallon income tax credit is allowed for ethanol used as a motor fuel (the "alcohol fuels credit"). The benefit of the alcohol fuels tax credit may be claimed as a reduction in excise tax payments when the ethanol is blended with gasoline ("gasohol"). The reduction is based on the amount of ethanol contained in the gasohol. The excise tax benefits apply to gasohol blends of 90 percent gasoline/10 percent ethanol, 92.3 percent gasoline/7.7 percent ethanol, or 94.3 percent gasoline/5.7 percent ethanol. The income tax credit is based on the amount of alcohol contained in the blended fuel.

ETBE is an ether that is manufactured using ethanol. Unlike ethanol, ETBE can be blended with gasoline before the gasoline enters a pipeline because ETBE does not result in contamination of fuel with water while in transport. Treasury Department regulations provide that gasohol blenders may claim the income tax credit and excise tax rate reductions for ethanol used in the production of ETBE. The regulations also a special election allowing refiners to claim the benefit of the excise tax rate reduction even though the fuel being removed from terminals does not contain the requisite percentages of ethanol for claiming the excise tax rate reduction.

Description of Proposal

The proposal would replace the present-law regulatory procedures enabling refiners to claim excise tax benefits on ETBE-blended gasohol with a new excise tax credit alternative to the alcohol fuels income tax credit. Under the proposal, in lieu of excise tax rate reductions for specified gasohol blends, a refiner blending ETBE and ethanol would accrue an excise tax credit equal to the amount of the alcohol fuels credit or excise tax rate reduction otherwise available for the ETBE blended fuel. The refiner could use this credit to offset its excise tax liability for highway motor fuels under Code section 4081. Alternatively, the credit could be transferred to a registered position holder that is a member of the same controlled group as the refiner, and the position holder could use the excise tax credit to offset its liability for excise taxes under those Code sections.

Effective Date

The proposal would be effective for fuels blended after date of enactment.

III. CONSERVATION AND ENERGY EFFICIENCY PROVISIONS

A. Business Credit for Construction of New Energy-Efficient Homes

Present Law

A nonrefundable, 10-percent business energy credit is allowed for the cost of new property that is equipment (1) that uses solar energy to generate electricity, to heat or cool a structure, or to provide solar process heat, or (2) used to produce, distribute, or use energy derived from a geothermal deposit, but only, in the case of electricity generated by geothermal power, up to the electric transmission stage.

The business energy tax credits are components of the general business credit (sec. 38(b)(1)). The business energy tax credits, when combined with all other components of the general business credit, generally may not exceed for any taxable year the excess of the taxpayer's net income tax over the greater of (1) 25 percent of net regular tax liability above $25,000 or (2) the tentative minimum tax. For credits arising in taxable years beginning after December 31, 1997, an unused general business credit generally may be carried back one year and carried forward 20 years (sec. 39).

A taxpayer may exclude from income the value of any subsidy provided by a public utility for the purchase or installation of an energy conservation measure. An energy conservation measure means any installation or modification primarily designed to reduce consumption of electricity or natural gas or to improve the management of energy demand with respect to a dwelling unit (sec. 136).

There is no present-law credit for the construction of new energy-efficient homes.

Description of Proposal

The proposal would provide a credit to an eligible contractor of an amount equal to the aggregate adjusted bases of all energy-efficient property installed in a qualified new energy-efficient home during construction. The credit cannot exceed $1,250 ($2,000) in the case of a new home which has a projected level of annual heating and cooling costs that is 30 percent (50 percent) less than a comparable dwelling constructed in accordance with Chapter 4 of the 2000 International Energy Conservation Code.

The eligible contractor would be the person who constructed the home, or in the case of a manufactured home, the producer of such home. Energy efficiency property would be any energy-efficient building envelope component (insulation materials or system designed to reduce heat loss or gain, and exterior windows, including skylights, and doors) and any energy-efficient heating or cooling appliance that can, individually or in combination with other components, meet the standards for the home.

To qualify as an energy-efficient new home, the home must be: (1) a dwelling located in the United States; (2) the principal residence of the person who acquires the dwelling from the eligible contractor; and (3) certified to have a projected level of annual heating and cooling

energy consumption that meets the standards for either the 30-percent or 50-percent credit. The home may be certified according to a component-based method or an energy performance based method.

Effective Date

The credit applies to homes whose construction is substantially completed after the date of enactment and which are purchased during the period beginning on the date of enactment and ending on December 31, 2007.

B. Tax Credit for Energy-Efficient Appliances

Present Law

A nonrefundable, 10-percent business energy credit is allowed for the cost of new property that is equipment: (1) that uses solar energy to generate electricity, to heat or cool a structure, or to provide solar process heat; or (2) used to produce, distribute, or use energy derived from a geothermal deposit, but only, in the case of electricity generated by geothermal power, up to the electric transmission stage.

The business energy tax credits are components of the general business credit (sec. 38(b)(1)). The business energy tax credits, when combined with all other components of the general business credit, generally may not exceed for any taxable year the excess of the taxpayer's net income tax over the greater of: (1) 25 percent of net regular tax liability above $25,000 or (2) the tentative minimum tax. For credits arising in taxable years beginning after December 31, 1997, an unused general business credit generally may be carried back one year and carried forward 20 years (sec. 39).

A taxpayer may exclude from income the value of any subsidy provided by a public utility for the purchase or installation of an energy conservation measure. An energy conservation measure means any installation or modification primarily designed to reduce consumption of electricity or natural gas or to improve the management of energy demand with respect to a dwelling unit (sec. 136).

There is no present-law credit for the manufacture of energy-efficient appliances.

Description of Proposal

The proposal would provide a credit for the production of certain energy-efficient clothes washers and refrigerators. The credit would equal $50 per appliance for energy-efficient clothes washers produced with a modified energy factor ("MEF") of 1.26 or greater and for refrigerators produced that consume 10 percent less kilowatt-hours per year than the energy conservation standards promulgated by the Department of Energy that took effect on July 1, 2001. The credit would equal $100 for energy-efficient clothes washers produced with a MEF of 1.42 or greater (1.5 or greater for washers produced after 2004) and for refrigerators produced that consume 15 percent less kilowatt-hours per year than the energy conservation standards promulgated by the Department of Energy that took effect on July 1, 2001. An energy-efficient refrigerator would be an automatic defrost refrigerator-freezer with an internal volume of at least 16.5 cubic feet to qualify for the credit. An energy-efficient clothes washer would be any residential clothes washer, including a residential style coin operated washer.

For each category of appliances (i.e., washers that meet the lower MEF standard, washers that meet the higher MEF standard, refrigerators that meet the 10 percent standard, refrigerators that meet the 15 percent standard), only production in excess of average production for each such category during calendar years 1999-2001 would be eligible for the credit. The taxpayer may not claim credits in excess of $30 million for all taxable years for appliances that qualify for the $50 credit, and may not claim credits in excess of $30 million for all taxable years for appliances that

qualify for the $100 credit. Additionally, the credit allowed for all appliances may not exceed two percent of the average annual gross receipts of the taxpayer for the three taxable years preceding the taxable year in which the credit is determined. The present-law carry back rules of the general business credit generally would apply except that no credits attributable to energy-efficient appliances may be carried back before the effective date of this provision.

Effective Date

The credit would apply to appliances produced after December 31, 2002 and prior to (1) January 1, 2005 in the case of refrigerators that only meet the 10 percent credit standard, or (2) January 1, 2007 in the case of all other qualified energy-efficient appliances.

C. Tax Credit for Residential Fuel Cell, Solar and Wind Energy

Present Law

A nonrefundable, 10-percent business energy credit is allowed for the cost of new property that is equipment (1) that uses solar energy to generate electricity, to heat or cool a structure, or to provide solar process heat, or (2) used to produce, distribute, or use energy derived from a geothermal deposit, but only, in the case of electricity generated by geothermal power, up to the electric transmission stage.

The business energy tax credits are components of the general business credit (sec. 38(b)(1)). The business energy tax credits, when combined with all other components of the general business credit, generally may not exceed for any taxable year the excess of the taxpayer's net income tax over the greater of (1) 25 percent of net regular tax liability above $25,000 or (2) the tentative minimum tax. For credits arising in taxable years beginning after December 31, 1997, an unused general business credit generally may be carried back one year and carried forward 20 years (sec. 39).

A taxpayer may exclude from income the value of any subsidy provided by a public utility for the purchase or installation of an energy conservation measure. An energy conservation measure means any installation or modification primarily designed to reduce consumption of electricity or natural gas or to improve the management of energy demand with respect to a dwelling unit (sec. 136).

There is no present-law personal tax credit for residential fuel cell, solar or wind energy property.

Description of Proposal

The proposal would provide a personal tax credit for the purchase of qualified wind energy property, qualified photovoltaic property, and qualified solar water heating property that is used exclusively for purposes other than heating swimming pools and hot tubs. The credit would be equal to 15 percent for solar water heating property and photovoltaic property, and would be equal to 30 percent for wind energy property. The maximum credit for each of these systems of property would be $2,000. The proposal would also provide a 30 percent credit for the purchase of qualified stationary or portable fuel cell power plants. The credit for any fuel cell may not exceed $1,000 for each kilowatt of capacity.

The credit would be nonrefundable and would be allowed against the regular and minimum tax. The depreciable basis of the property would be reduced by the amount of the credit.

Qualifying solar water heating property would mean an expenditure for property to heat water for use in a dwelling unit located in the United States and used as a residence if at least half of the energy used by such property for such purpose is derived from the sun. Qualified photovoltaic property would be property that uses solar energy to generate electricity for use in a dwelling unit. Solar panels would be treated as qualified photovoltaic property. Qualified wind energy property would be property that uses wind energy to generate electricity for use in a

dwelling unit. A qualified fuel cell power plant is an integrated system comprised of a fuel cell stack assembly and associated balance of plant components that converts a fuel into electricity using electrochemical means, and which has an electricity-only generation efficiency of greater than 30 percent and generates at least 1 kilowatt of electricity using an electrochemical process. The qualified fuel cell power plant must be installed on or in connection with a dwelling unit located in the United States and used by the taxpayer as a principal residence. Expenditures for labor costs allocable to onsite preparation, assembly, or original installation of property eligible for the credit would be eligible expenditures.

Certain equipment safety requirements would need to be met to qualify for the credit. Special proration rules would apply in the case of jointly owned property, condominiums, and tenant-stockholders in cooperative housing corporations.

Effective Date

The credit would apply to purchases after December 31, 2002 and before January 1, 2008.

D. Business Tax Incentives for Fuel Cells

Present Law

A nonrefundable, 10-percent business energy credit is allowed for the cost of new property that is equipment (1) that uses solar energy to generate electricity, to heat or cool a structure, or to provide solar process heat, or (2) used to produce, distribute, or use energy derived from a geothermal deposit, but only, in the case of electricity generated by geothermal power, up to the electric transmission stage.

The business energy tax credits are components of the general business credit (sec. 38(b)(1)). The business energy tax credits, when combined with all other components of the general business credit, generally may not exceed for any taxable year the excess of the taxpayer's net income tax over the greater of (1) 25 percent of net regular tax liability above $25,000 or (2) the tentative minimum tax. For credits arising in taxable years beginning after December 31, 1997, an unused general business credit generally may be carried back one year and carried forward 20 years (sec. 39).

A taxpayer may exclude from income the value of any subsidy provided by a public utility for the purchase or installation of an energy conservation measure. An energy conservation measure means any installation or modification primarily designed to reduce consumption of electricity or natural gas or to improve the management of energy demand with respect to a dwelling unit (sec. 136).

There is no present-law credit for fuel cell power plant property.

Description of Proposal

The proposal would provide a 30 percent credit for the purchase of qualified fuel cell power plants for businesses. A qualified fuel cell power plant is an integrated system comprised of a fuel cell stack assembly and associated balance of plant components that converts a fuel into electricity using electrochemical means, and which has an electricity-only generation efficiency of greater than 30 percent and which generates at least 1 kilowatt of electricity. The credit for any fuel cell may not exceed $1,000 for each kilowatt of capacity. The credit would be nonrefundable. The taxpayer's basis in the property would be reduced by the amount of the credit claimed.

Effective Date

The credit for businesses would apply to property placed in service after December 31, 2002 and before January 1, 2007, under rules similar to rules of section 48(m) of the Internal Revenue Code of 1986 (as in effect on the day before the date of enactment of the Revenue Reconciliation Act of 1990).

E. Allowance of Deduction for Energy-Efficient Commercial Building Property

Present Law

No special deduction is currently provided for expenses incurred for energy-efficient commercial building property.

Description of Proposal

The proposal would provide a deduction equal to energy-efficient commercial building property expenditures made by the taxpayer. Energy-efficient commercial building property expenditures would be amounts paid or incurred for energy-efficient commercial building property installed in connection with the new construction or reconstruction of property: (1) which would otherwise be depreciable property; (2) which is located in the United States, and (3) the construction or erection of which is completed by the taxpayer. The deduction would be limited to an amount equal to the product of $2.25 and the square footage of the property for which such expenditures were made. The deduction would be allowed in the year in which the property is placed in service.

Energy-efficient commercial building property would mean any property that reduces total annual energy and power costs with respect to the lighting, heating, cooling, ventilation, and hot water supply systems of the building by 50 percent or more in comparison to a reference building which meets the requirements of a Standard 90.1-1999 of the American Society of Heating, Refrigerating, and Air Conditioning Engineers and the Illuminating Engineering Society of North America. Certain certification requirements would have to be met.

For public property, such as schools, the Secretary would issue regulations to allow the deduction to be allocated to the person primarily responsible for designing the property in lieu of the public entity owner. Other rules would apply.

Effective Date

The proposal is effective for taxable years beginning after October 1, 2002 for plans certified prior to December 31, 2007, whose construction is completed on or before December 31, 2009.

F. Allowance of Deduction for Qualified Energy Management Devices and Retrofitted Qualified Meters

Present Law

No special deduction is currently provided for expenses incurred for qualified energy management devices.

Description of Proposal

The proposal would provide a $30 deduction for each qualified new or retrofitted energy management device placed in service by any taxpayer who is a supplier of electric energy or natural gas or is a provider of electric energy or natural gas services. A qualified energy management device would be any tangible property eligible for accelerated depreciation under section 168 and which is acquired and used by the taxpayer to enable consumers or others to manage their purchase, sale, or use of electricity in response to energy price and usage signals and which permits reading of energy price and usage signals on at least a daily basis.

The deduction would not be allowed to property used outside of the United States. The taxpayer would have basis reduction for such property equal to the deduction. Other rules would apply.

Effective Date

The proposal would be effective for any qualified energy management device placed in service after the date of enactment of the Act.

G. Three-Year Applicable Recovery Period for Depreciation of Qualified Energy Management Devices

Present Law

No special recovery period is currently provided for depreciation of qualified energy management devices.

Description of Proposal

The proposal would provide a 3-year recovery period for qualified new or retrofitted energy management devices placed in service by any taxpayer who is a supplier of electric energy or natural gas or is a provider of electric energy or natural gas services. A qualified energy management device would be any tangible property eligible for accelerated depreciation under code section 168 and which is acquired and used by the taxpayer to enable consumers or others to manage their purchase, sale, or use of electricity in response to energy price and usage signals and which permits reading of energy price and usage signals on at least a daily basis.

Effective Date

The proposal would be effective for any qualified energy management device placed in service after the date of enactment of the Act.

H. Energy Credit for Combined Heat and Power System Property

Present Law

A nonrefundable, 10-percent business energy credit is allowed for the cost of new property that is equipment (1) that uses solar energy to generate electricity, to heat or cool a structure, or to provide solar process heat, or (2) used to produce, distribute, or use energy derived from a geothermal deposit, but only, in the case of electricity generated by geothermal power, up to the electric transmission stage.

The business energy tax credits are components of the general business credit (sec. 38(b)(1)). The business energy tax credits, when combined with all other components of the general business credit, generally may not exceed for any taxable year the excess of the taxpayer's net income tax over the greater of (1) 25 percent of net regular tax liability above $25,000 or (2) the tentative minimum tax. For credits arising in taxable years beginning after December 31, 1997, an unused general business credit generally may be carried back one year and carried forward 20 years (sec. 39).

A taxpayer may exclude from income the value of any subsidy provided by a public utility for the purchase or installation of an energy conservation measure. An energy conservation measure means any installation or modification primarily designed to reduce consumption of electricity or natural gas or to improve the management of energy demand with respect to a dwelling unit (sec. 136).

There is no present-law credit for combined heat and power ("CHP") property.

Description of Proposal

The proposal would provide a 10 percent credit for the purchase of combined heat and power property.

CHP property would mean property: (1) which uses the same energy source for the simultaneous or sequential generation of electrical power, mechanical shaft power, or both, in combination with the generation of steam or other forms of useful thermal energy (including heating and cooling applications); (2) which has an electrical capacity of more than 50 kilowatts or a mechanical energy capacity of more than 67 horsepower or an equivalent combination of electrical and mechanical energy capacities; (3) which produces at least 20 percent of its total useful energy in the form of thermal energy and at least 20 percent in the form of electrical or mechanical power (or a combination thereof); and (4) the energy efficiency percentage of which exceeds 60 percent (70 percent in the case of a system with an electrical capacity in excess of 50 megawatts or a mechanical energy capacity in excess of 67,000 horsepower, or an equivalent combination of electrical and mechanical capacities.)

CHP property would not include property used to transport the energy source to the generating facility or to distribute energy produced by the facility.

If a taxpayer is allowed a credit for CHP property, and the property would ordinarily have a depreciation class life of 15 years or less, the depreciation period for the property is treated as having a 22-year class life. The present-law carry back rules of the general business credit generally would apply except that no credits attributable to combined heat and power property may be carried back before the effective date of this provision.

Effective Date

The credit would apply to property placed in service after December 31, 2002 and before January 1, 2007.

IV. CLEAN COAL INCENTIVES

A. Investment and Production Credits for Clean Coal Technology

Present Law

Present law does not provide an investment credit for electricity generating facilities that use coal as a fuel. Nor does present law provide a production credit for electricity generated at facilities that use coal as a fuel. However, a nonrefundable, 10-percent investment tax credit ("business energy credit") is allowed for the cost of new property that is equipment (1) that uses solar energy to generate electricity, to heat or cool a structure, or to provide solar process heat, or (2) that is used to produce, distribute, or use energy derived from a geothermal deposit, but only, in the case of electricity generated by geothermal power, up to the electric transmission stage (sec. 48). Also, an income tax credit is allowed for the production of electricity from either qualified wind energy, qualified "closed-loop" biomass, or qualified poultry waste facilities placed in service prior to January 1, 2002 (sec. 45). The credit allowed equals 1.5 cents per kilowatt-hour of electricity sold. The 1.5 cent figure is indexed for inflation and equals 1.7 cents for 2001. The credit is allowable for production during the 10-year period after a facility is originally placed in service. The business energy tax credits and the production tax credit are components of the general business credit (sec. 38(b)(1)).

Description of Proposal

In general

The proposal would create three new credits: a production credit for electricity produced from qualifying clean coal technology units; a production credit for electricity produced from qualifying advanced clean coal technology; and a credit for investments in qualifying advanced clean coal technology facilities. Certain persons (public utilities, electric cooperatives, and the Tennessee Valley Authority) would be eligible to obtain certifications from the Secretary of the Treasury (as described below) for each of these credits and sell, trade, or assign the credit to any taxpayer.

Credit for investments in qualifying advanced clean coal technology facilities

The proposal would provide a 10-percent investment tax credit for qualified investments in advanced clean coal technology facilities. Qualifying advanced clean coal electricity production facilities must utilize advanced pulverized coal or atmospheric fluidized bed combustion technology, pressurized fluidized bed combustion technology, integrated gasification combined cycle technology, or some other technology certified by the Secretary of Energy. Any qualifying facility must meet certain capacity standards, thermal efficiency standards, and emissions standards for SO_2, nitrous oxides, particulate emissions, and source emissions standards as provided in the Clean Air Act. A qualifying advanced clean coal facility would not include any facility that uses "refined coal" (as defined Part V.J., of this document). In addition, the taxpayer would not be able to claim any investment credit with respect to a facility for which the taxpayer is not eligible to claim a production credit for electricity produced from any qualified advanced clean coal technology electricity generation unit as described below.

To be a qualified investment in advanced clean coal technology, the taxpayer must receive a certificate from the Secretary of the Treasury. The Secretary may grant certificates to investments only to the point that 4,000 megawatts of electricity production capacity qualifies for the credit. From the potential pool of 4,000 megawatts of capacity, not more than 1,000 megawatts in total and not more than 500 megawatts in years prior to 2009 shall be allocated to facilities using advanced pulverized coal or atmospheric fluidized bed combustion technology. From the potential pool of 4,000 megawatts of capacity, not more than 500 megawatts in total and not more than 250 megawatts in years prior to 2009 shall be allocated to facilities using pressurized fluidized bed combustion technology. From the potential pool of 4,000 megawatts of capacity, not more than 2,000 megawatts in total and not more than 1,000 megawatts in years prior to 2009 and not more than 1,500 megawatts in year prior to 2013 shall be allocated to facilities using integrated gasification combined cycle technology, with or without fuel or chemical co-production. From the potential pool of 4,000 megawatts of capacity, not more than 500 in total and not more than 250 megawatts in years prior to 2009 shall be allocated to any other technology for which a carbon emission rate is not more than 85 percent of conventional technology.

Production credit for electricity produced from qualifying clean coal technology units

The proposal provides a production credit for electricity produced from certain facilities that have been retrofitted, repowered, or replaced with a clean coal technology within ten years of the date of enactment. The value of the credit is 0.34 cents per kilowatt-hour of electricity produced and is indexed for inflation occurring after 2002 with the first potential adjustment in 2004. The taxpayer may claim the credit throughout the ten-year period commencing from the date on which the qualifying facility is placed in service.

A qualifying clean coal technology unit is a facility that meets certain capacity standards, thermal efficiency standards, and emissions standards for SO_2, nitrous oxides, particulate emissions, and source emissions standards as provided in the Clean Air Act. In addition, a qualifying clean coal technology unit would not be a facility that is receiving or is scheduled to receive funding under the Clean Coal Technology Program, the Power Plant Improvement Initiative, or the Clean Coal Power Initiative administered by the Secretary of the Department of Energy. Lastly, to be a qualified clean coal technology unit, the taxpayer must receive a certificate from the Secretary of the Treasury. The Secretary may grant certificates to facilities only to the point that 4,000 megawatts of electricity production capacity qualifies for the credit. However, no qualifying facility would be eligible if the facility's capacity exceeded 300 megawatts.

Production credit for electricity produced from qualifying advanced clean coal technology

The proposal also would provide a production credit for electricity produced from any qualified advanced clean coal technology electricity generation unit that qualifies for the investment credit for qualifying clean coal technology facilities, as described above. The production credit would be claimed on the sum of each kilowatt-hour of electricity produced and

the heat value of other fuels or chemicals produced by the taxpayer at the facility.[2] The production credit would be claimed for the 10-year period commencing with the date the qualifying facility is placed in service. The value of the credit would vary depending upon the year the facility was placed in service, whether the facility produces solely electricity or electricity and fuels or chemicals, and the rated thermal efficiency of the facility. In addition, the value of the credit would be reduced for the second five years of eligible production. The value of the credit would be indexed for inflation occurring after 2002 with the first potential adjustment in 2004. The tables below specify the value of the credit (before indexing is applied).

Advanced clean coal technology facilities producing solely electricity

Facilities placed in service before 2009

The facility net heat rate, Btu/kWh adjusted for the heat content for the design coal is equal to:	Credit amount per kilowatt-hour	
	For the first five years	For the second five years
Not more than 8,400	$.0060	$.0038
More than 8,400 but not more than 8,550	$.0025	$.0010
More than 8,550 but less than 8,750	$.0010	$.0010

Facilities placed in service after 2008 and before 2013

The facility net heat rate, Btu/kWh adjusted for the heat content for the design coal is equal to:	Credit amount per kilowatt-hour	
	For the first five years	For the second five years
Not more than 7,770	$.0105	$.0090
More than 7,770 but not more than 8,125	$.0085	$.0068
More than 8,125 but less than 8,350	$.0075	$.0055

[2] Each 3,413 Btu of heat content of the fuel or chemical is treated as equivalent to one kilowatt-hour of electricity.

Facilities placed in service after 2012 and before 2017

The facility net heat rate, Btu/kWh adjusted for the heat content for the design coal is equal to:	Credit amount per kilowatt-hour	
	For the first five years	For the second five years
Not more than 7,380	$.0140	$.0115
More than 7,380 but not more than 7,720	$.0120	$.0090

Advanced clean coal technology facilities producing electricity and a fuel or chemical

Facilities placed in service before 2009

The facility design net thermal efficiency is equal to:	Credit amount per kilowatt-hour	
	For the first five years	For the second five years
Not less than 40.6%	$.0060	$.0038
Less than 40.6% but not less than 40%	$.0025	$.0010
Less than 40% but not less than 39%	$.0010	$.0010

Facilities placed in service after 2008 and before 2013

The facility design net thermal efficiency is equal to:	Credit amount per kilowatt-hour	
	For the first five years	For the second five years
Not less than 43.9%	$.0105	$.0090
Less than 43.9% but not less than 42%	$.0085	$.0068
Less than 42% but not less than 40.9%	$.0075	$.0055

Facilities placed in service after 2012 and before 2017

The facility design net thermal efficiency is equal to:	Credit amount per kilowatt-hour	
	For the first five years	For the second five years
Not less than 44.2%	$.0140	$.0115
Less than 44.2% but not less than 43.6%	$.0120	$.0090

Effective Date

The proposal relating to investment credits for advanced clean coal technology facilities would be effective after the date of enactment. The proposals relating to production credits would be effective after the date of enactment.

V. OIL AND GAS PROVISIONS

A. Tax Credit for Oil and Gas Production from Marginal Wells

Present Law

There is no credit for the production of oil and gas from marginal wells. The costs of such production may be recovered under the Code's depreciation and depletion rules and in other cases as a deduction for ordinary and necessary business expenses.

Description of Proposal

The proposal would create a new, $3 per barrel credit for the production of crude oil and a $0.50 credit per 1,000 cubic feet of qualified natural gas production. The maximum amount of production on which credit could be claimed would be 1,095 barrels or barrel equivalents. In both cases, the credit would be available only for production from a "qualified marginal well." The credit would not be available to production occurring if the reference price of oil exceeded $18 ($2.00 for natural gas). The credit would be reduced proportionately as for reference prices between $15 and $18 ($1.67 and $2.00 for natural gas). Reference prices would be determined on a one-year look-back basis.

A qualified marginal well would be defined as (1) a well production from which was marginal production for purposes of the Code percentage depletion rules or (2) a well that during the taxable year had (a) average daily production of not more than 25 barrel equivalents and (b) produced water at a rate of not less than 95 percent of total well effluent.

The credit would be treated as a general business credit.

Effective Date

The proposal would be effective for production in taxable years beginning after the date of enactment.

B. Natural Gas Gathering Lines Treated as Seven-Year Property

Present Law

The applicable recovery period for assets placed in service under the Modified Accelerated Cost Recovery System is based on the "class life of the property." The class lives of assets placed in service after 1986 are generally set forth in Revenue Procedure 87-56.[3] Revenue Procedure 87-56 includes two asset classes that could describe natural gas gathering lines owned by nonproducers of natural gas. Asset class 46.0, describing pipeline transportation, provides a class life of 22 years and a recovery period of 15 years. Asset class 13.2, describing assets used in the exploration for and production of petroleum and natural gas deposits, provides a class life of 14 years and a depreciation recovery period of seven years. The uncertainty regarding the appropriate recovery period of natural gas gathering lines has resulted in litigation between taxpayers and the IRS. The 10th Circuit Court of Appeals held that natural gas gathering lines owned by nonproducers falls within the scope of Asset class 13.2 (i.e., 7-year recovery period).[4] More recently, the U.S. District Court for the Eastern District of Michigan, Southern Division, held that natural gas gathering lines owned by nonproducers falls within the scope of Asset class 46.0 (i.e., 15-year recovery period).[5]

Description of Proposal

The proposal would establish a statutory 7-year recovery period and a class life of 10 years for natural gas gathering lines. A natural gas gathering line would be defined to include any pipe, equipment, and appurtenance that is (1) determined to be a gathering line by the Federal Energy Regulatory Commission, or (2) used to deliver natural gas from the wellhead or a common point to the point at which such gas first reaches (a) a gas processing plant, (b) an interconnection with an interstate transmission line, (c) an interconnection with an intrastate transmission line, or (d) a direct interconnection with a local distribution company, a gas storage facility, or an industrial consumer.

Effective Date

The proposal would be effective for property placed in service after date of enactment.

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[3] 1987-2 C.B. 674 (as clarified and modified by Rev. Proc. 88-22, 1988-1 C.B. 785).

[4] *Duke Energy v. Commissioner*, 172 F.3d 1255 (10th Cir. 1999), *rev'g* 109 T.C. 416 (1997). See also *True v. United States*, 97-2 U.S. Tax Cas. (CCH) par. 50,946 (D. Wyo. 1997).

[5] *Saginaw Bay Pipeline Co. v. United States*, 124 F. Supp. 2d 465 (E.D. Mich. 2001).

C. Repeal of Requirement of Certain Approved Terminals to Offer Dyed Diesel or Kerosene for Nontaxable Purposes

Present and Prior Law

Excise taxes are imposed on highway motor fuels, including gasoline, diesel fuel, and kerosene, to finance the Highway Trust Fund programs. Subject to limited exceptions, these taxes are imposed on all such fuels when they are removed from registered pipeline or barge terminal facilities, with any tax-exemptions being accomplished by means of refunds to consumers of the fuel. One such exception allows removal of diesel fuel and kerosene without payment of tax if the fuel is destined for a nontaxable use (e.g., use as heating oil) and is indelibly dyed.

Terminal facilities are not permitted to receive and store non-tax-paid motor fuels unless they are registered with the Internal Revenue Service. Under present law, a prerequisite to registration is that if the terminal offers for sale diesel fuel, it must offer both dyed and undyed diesel fuel. Similarly, if the terminal offers for sale kerosene, it must offer both dyed and undyed kerosene. This "dyed-fuel mandate" was enacted in 1997, to be effective on July 1, 1998. Subsequently, the effective date was delayed until July 1, 2000 and delayed again through December 31, 2001.

Description of Proposal

The proposal would repeal the diesel fuel and kerosene-dyeing mandate.

Effective Date

The proposal would be effective on January 1, 2002.

D. Expensing of Capital Costs Incurred and Credit for Production in Complying with Environmental Protection Agency Sulfur Regulations

Present Law

Taxpayers generally may recover the costs of investments in refinery property through annual depreciation deductions. Present law does not provide a credit for the production of low-sulfur diesel fuel.

Description of Proposal

The proposal would permit small business refiners to claim an immediate deduction (i.e., expensing) for up to 75 percent of the costs paid or incurred for the purpose of complying with the Highway Diesel Fuel Sulfur Control Requirements of the Environmental Protection Agency.

In addition, the proposal would provide that a small business refiner may claim a credit equal to five cents per gallon for each gallon of low sulfur diesel fuel produced during the period beginning one year after the date of enactment and ending with the date that is one year after the date on which the taxpayer must comply with applicable EPA regulations for the refinery. The total production credit claimed by the taxpayer would be limited to 25 percent of the capital costs incurred to come into compliance with the EPA diesel fuel requirements. No deduction would be allowed to the taxpayer for expenses otherwise allowable as a deduction in an amount equal to the amount of production credit claimed during the taxable year.

For these purposes a small business refiner is a taxpayer who within the business of refining petroleum products employs not more than 1,500 employees directly in refining on business days during a taxable year in which the deduction or production credit is claimed and had an average daily refinery run not exceeding 155,000 barrels per day for the year prior to enactment.

For taxpayers with an average daily refinery run in the year prior to enactment in excess of 155,000 and not greater than 205,000 barrels per day, the proposal would permit otherwise qualifying small business refiners to claim an immediate deduction for a percentage of qualifying capital costs equal to 75 percent less the percentage points determined by the excess of the average daily refinery runs over 155,000 barrels per day divided by 50,000 barrels per day. In addition, for these taxpayers, the limitation on the total production credit that may be claimed is reduced proportionately.

In the case of a qualifying small business refiner that is owned by a cooperative, the cooperative would be allowed to elect to pass any production credits to patrons of the organization.

Effective Date

The proposal would be effective for expenses paid or incurred after the date of enactment.

E. Determination of Small Refiner Exception to Oil Depletion Deduction

Present Law

Present law classifies oil and gas producers as independent producers or integrated companies. The Code provides numerous special tax rules for operations by independent producers. One such rule allows independent producers to claim percentage depletion deductions rather than deducting the costs of their asset, a producing well, based on actual production from the well (i.e., cost depletion).

A producer is an independent producer only if its refining and retail operations are relatively small. For example, an independent producer may not have refining operations the runs from which exceed 50,000 barrels on any day in the taxable year during which independent producer status is claimed.

Description of Proposal

The proposal would change the refinery limitation on claiming independent producer status from a limit based on actual daily production to a limit based on average daily production for the taxable year. Accordingly, the average daily refinery run for the taxable year could not exceed 50,000 barrels. For this purpose, the taxpayer would calculate average daily refinery run by dividing total production for the taxable year by the total number of days in the taxable year.

Effective Date

The proposal would be effective for taxable years beginning after December 31, 2002.

F. Extension of Suspension of Taxable Income Limit With Respect to Marginal Production

Present Law

In general

Depletion, like depreciation, is a form of capital cost recovery. In both cases, the taxpayer is allowed a deduction in recognition of the fact that an asset--in the case of depletion for oil or gas interests, the mineral reserve itself--is being expended in order to produce income. Certain costs incurred prior to drilling an oil or gas property are recovered through the depletion deduction. These include costs of acquiring the lease or other interest in the property and geological and geophysical costs (in advance of actual drilling).

Depletion is available to any person having an economic interest in a producing property. An economic interest is possessed in every case in which the taxpayer has acquired by investment any interest in minerals in place, and secures, by any form of legal relationship, income derived from the extraction of the mineral, to which it must look for a return of its capital.[6] Thus, for example, both working interests and royalty interests in an oil- or gas-producing property constitute economic interests, thereby qualifying the interest holders for depletion deductions with respect to the property. A taxpayer who has no capital investment in the mineral deposit does not possess an economic interest merely because it possesses an economic or pecuniary advantage derived from production through a contractual relation.

Cost depletion

Two methods of depletion are currently allowable under the Internal Revenue Code (the "Code"): (1) the cost depletion method, and (2) the percentage depletion method (secs. 611-613). Under the cost depletion method, the taxpayer deducts that portion of the adjusted basis of the depletable property which is equal to the ratio of units sold from that property during the taxable year to the number of units remaining as of the end of taxable year plus the number of units sold during the taxable year. Thus, the amount recovered under cost depletion may never exceed the taxpayer's basis in the property.

Percentage depletion and related income limitations

The Code generally limits the percentage depletion method for oil and gas properties to independent producers and royalty owners.[7] Generally, under the percentage depletion method 15 percent of the taxpayer's gross income from an oil- or gas-producing property is allowed as a deduction in each taxable year (sec. 613A(c)). The amount deducted generally may not exceed 100 percent of the net income from that property in any year (the "net-income limitation") (sec. 613(a)). By contrast, for any other mineral qualifying for the percentage depletion deduction, such deduction may not exceed 50 percent of the taxpayer's taxable income from the depletable

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[6] Treas. Reg. sec. 1.611-1(b)(1).

[7] Sec. 613A.

property. A similar 50-percent net-income limitation applied to oil and gas properties for taxable years beginning before 1991. Section 11522(a) of the Omnibus Budget Reconciliation Act of 1990 prospectively changed the net-income limitation threshold to 100 percent only for oil and gas properties, effective for taxable years beginning after 1990. The 100-percent net-income limitation for marginal wells has been suspended for taxable years beginning after December 31, 1997, and before January 1, 2002.

Additionally, the percentage depletion deduction for all oil and gas properties may not exceed 65 percent of the taxpayer's overall taxable income (determined before such deduction and adjusted for certain loss carrybacks and trust distributions) (sec. 613A(d)(1)).[8] Because percentage depletion, unlike cost depletion, is computed without regard to the taxpayer's basis in the depletable property, cumulative depletion deductions may be greater than the amount expended by the taxpayer to acquire or develop the property.

A taxpayer is required to determine the depletion deduction for each oil or gas property under both the percentage depletion method (if the taxpayer is entitled to use this method) and the cost depletion method. If the cost depletion deduction is larger, the taxpayer must utilize that method for the taxable year in question (sec. 613(a)).

Limitation of oil and gas percentage depletion to independent producers and royalty owners

Generally, only independent producers and royalty owners (as contrasted to integrated oil companies) are allowed to claim percentage depletion. Percentage depletion for eligible taxpayers is allowed only with respect to up to 1,000 barrels of average daily production of domestic crude oil or an equivalent amount of domestic natural gas (sec. 613A(c)). For producers of both oil and natural gas, this limitation applies on a combined basis.

In addition to the independent producer and royalty owner exception, certain sales of natural gas under a fixed contract in effect on February 1, 1975, and certain natural gas from geopressured brine,[9] are eligible for percentage depletion, at rates of 22 percent and 10 percent, respectively. These exceptions apply without regard to the 1,000-barrel-per-day limitation and regardless of whether the producer is an independent producer or an integrated oil company.

Description of Proposal

The suspension of the 100-percent net-income limitation for marginal wells would be extended an additional five years, through taxable years beginning before January 1, 2007.

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[8] Amounts disallowed as a result of this rule may be carried forward and deducted in subsequent taxable years, subject to the 65-percent taxable income limitation for those years.

[9] This exception is limited to wells, the drilling of which began between September 30, 1978, and January 1, 1984.

Effective Date

The proposal would be effective on date of enactment for taxable years after December 31, 2001.

G. Amortization of Geological and Geophysical Expenditures

Present Law

In general

Geological and geophysical expenditures are costs incurred by a taxpayer for the purpose of obtaining and accumulating data that will serve as the basis for the acquisition and retention of mineral properties by taxpayers exploring for minerals. A key issue with respect to the tax treatment of such expenditures is whether or not they are capital in nature. Capital expenditures are not currently deductible as ordinary and necessary business expenses, but are allocated to the cost of the property.[10]

Courts have held that geological and geophysical costs are capital, and therefore are allocable to the cost of the property[11] acquired or retained.[12] The costs attributable to such exploration are allocable to the cost of the property acquired or retained. As described further below, IRS administrative rulings have provided further guidance regarding the definition and proper tax treatment of geological and geophysical costs.

Revenue Ruling 77-188

In Revenue Ruling 77-188[13] (hereinafter referred to as the "1977 ruling"), the IRS provided guidance regarding the proper tax treatment of geological and geophysical costs. The ruling describes a typical geological and geophysical exploration program as containing the following elements:

- It is customary in the search for mineral producing properties for a taxpayer to conduct an exploration program in one or more identifiable project areas. Each

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[10] Under section 263, capital expenditures are defined generally as any amount paid for new buildings or for permanent improvements or betterments made to increase the value of any property or estate. Treasury regulations define capital expenditures to include amounts paid or incurred (1) to add to the value, or substantially prolong the useful life, of property owned by the taxpayer or (2) to adapt property to a new or different use. Treas. Reg. sec. 1.263(a)-1(b).

[11] "Property" means an interest in a property as defined in section 614 of the Code, and includes an economic interest in a tract or parcel of land notwithstanding that a mineral deposit has not been established or proved at the time the costs are incurred.

[12] See, *e.g., Schermerhorn Oil Corporation v. Commissioner,* 46 B.T.A. 151 (1942). By contrast, section 617 of the Code permits a taxpayer to elect to deduct certain expenditures incurred for the purpose of ascertaining the existence, location, extent, or quality of any deposit of ore or other mineral (but not oil and gas). These deductions are subject to recapture if the mine with respect to which the expenditures were incurred reaches the producing stage.

[13] 1977-1 C.B. 76.

project area encompasses a territory that the taxpayer determines can be explored advantageously in a single integrated operation. This determination is made after analyzing certain variables such as (1) the size and topography of the project area to be explored, (2) the existing information available with respect to the project area and nearby areas, and (3) the quantity of equipment, the number of personnel, and the amount of money available to conduct a reasonable exploration program over the project area.

- The taxpayer selects a specific project area from which geological and geophysical data are desired and conducts a reconnaissance-type survey utilizing various geological and geophysical exploration techniques. These techniques are designed to yield data that will afford a basis for identifying specific geological features with sufficient mineral potential to merit further exploration.

- Each separable, noncontiguous portion of the original project area in which such a specific geological feature is identified is a separate "area of interest." The original project area is subdivided into as many small projects as there are areas of interest located and identified within the original project area. If the circumstances permit a detailed exploratory survey to be conducted without an initial reconnaissance-type survey, the project area and the area of interest will be coextensive.

- The taxpayer seeks to further define the geological features identified by the prior reconnaissance-type surveys by additional, more detailed, exploratory surveys conducted with respect to each area of interest. For this purpose, the taxpayer engages in more intensive geological and geophysical exploration employing methods that are designed to yield sufficiently accurate sub-surface data to afford a basis for a decision to acquire or retain properties within or adjacent to a particular area of interest or to abandon the entire area of interest as unworthy of development by mine or well.

The 1977 ruling provides that if, on the basis of data obtained from the preliminary geological and geophysical exploration operations, only one area of interest is located and identified within the original project area, then the entire expenditure for those exploratory operations is to be allocated to that one area of interest and thus capitalized into the depletable basis of that area of interest. On the other hand, if two or more areas of interest are located and identified within the original project area, the entire expenditure for the exploratory operations is to be allocated equally among the various areas of interest.

If no areas of interest are located and identified by the taxpayer within the original project area, then the 1977 ruling states that the entire amount of the geological and geophysical costs related to the exploration is deductible as a loss under section 165. The loss is claimed in the taxable year in which that particular project area is abandoned as a potential source of mineral production.

A taxpayer may acquire or retain a property within or adjacent to an area of interest, based on data obtained from a detailed survey that does not relate exclusively to any discrete property within a particular area of interest. Generally, under the 1977 ruling, the taxpayer

allocates the entire amount of geological and geophysical costs to the acquired or retained property as a capital cost under section 263(a). If more than one property is acquired, it is proper to determine the amount of the geological and geophysical costs allocable to each such property by allocating the entire amount of the costs among the properties on the basis of comparative acreage.

If, however, no property is acquired or retained within or adjacent to that area of interest, the entire amount of the geological and geophysical costs allocable to the area of interest is deductible as a loss under section 165 for the taxable year in which such area of interest is abandoned as a potential source of mineral production.

In 1983, the IRS issued Revenue Ruling 83-105,[14] which elaborates on the positions set forth in the 1977 ruling by setting forth seven factual situations and applying the principles of the 1977 ruling to those situations. In addition, Revenue Ruling 83-105 explains what constitutes "abandonment as a potential source of mineral production."

Description of Proposal

The proposal would allow geological and geophysical costs incurred in connection with oil and gas exploration in the United States to be amortized over two years.

Effective Date

The proposal would be effective for geological and geophysical costs paid or incurred in taxable years beginning after December 31, 2002. No inference is intended from the prospective effective date of this proposal as to the proper treatment of pre-effective date geological and geophysical costs.

[14] 1983-2 C.B. 51.

H. Amortization of Delay Rental Payments

Present Law

Present law generally requires costs associated with inventory and property held for resale to be capitalized rather than currently deducted as they are incurred. (sec. 263). Oil and gas producers typically contract for mineral production in exchange for royalty payments. If mineral production is delayed, these contracts provide for "delay rental payments" as a condition of their extension. In proposed regulations issued in 2000, the Treasury Department took the position that the uniform capitalization rules of section 263A require delay rental payments to be capitalized.[15]

Description of Proposal

The proposal would allow delay rental payments incurred in connection with the development of oil or gas within the United States to be amortized over two years.

Effective Date

The proposal would apply to delay rental payments paid or incurred in taxable years beginning after December 31, 2002. No inference is intended from the prospective effective date of this proposal as to the proper treatment of pre-effective date delay rental payments.

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[15] 65 Fed. Reg. 6090 (2000).

I. Study of Coal Bed Methane

Present Law

Certain fuels produced from "non-conventional sources" and sold to unrelated parties are eligible for an income tax credit equal to $3 (generally adjusted for inflation) per barrel or BTU oil barrel equivalent (sec. 29). Qualified fuels must be produced within the United States.

Qualified fuels include:

(1) oil produced from shale and tar sands;

(2) gas produced from geopressured brine, Devonian shale, coal seams, tight formations ("tight sands"), or biomass; and

(3) liquid, gaseous, or solid synthetic fuels produced from coal (including lignite).

In general, the credit is available only with respect to fuels produced from wells drilled or facilities placed in service after December 31, 1979, and before January 1, 1993. An exception extends the January 1, 1993 expiration date for facilities producing gas from biomass and synthetic fuel from coal if the facility producing the fuel is placed in service before July 1, 1998, pursuant to a binding contract entered into before January 1, 1997.

The credit may be claimed for qualified fuels produced and sold before January 1, 2003 (in the case of non-conventional sources subject to the January 1, 1993 expiration date) or January 1, 2008 (in the case of biomass gas and synthetic fuel facilities eligible for the extension period).

Description of Proposal

The proposal would direct the Secretary of the Treasury to undertake a study of effect sec. 29 has had on the production of coal bed methane. The Secretary's study would be made in conjunction with the study to be undertaken by the Secretary of the Interior on the effects of coal bed methane production on surface and water resources, as provided in section 608 of S. 1766. The study would estimate the total amount of credit claimed annually and in aggregate related to the production of coal bed methane since the enactment of sec. 29. The study would report the annual value of the credit allowable for coal bed methane compared to the average annual wellhead price of natural gas (per thousand cubic feet of natural gas). The study would estimate the incremental increase in production of coal bed methane that has resulted from the enactment of sec. 29. The study would estimate the cost to the Federal government, in terms of the net tax benefits claimed, per thousand cubic feet of incremental coal bed methane produced annually and in aggregate since the enactment of sec. 29.

Effective Date

The proposal would be effective on the date of enactment.

J. Refined Coal

Present Law

Certain fuels produced from "non-conventional sources" and sold to unrelated parties are eligible for an income tax credit equal to $3 (generally adjusted for inflation) per barrel or BTU oil barrel equivalent (sec. 29). Qualified fuels must be produced within the United States.

Qualified fuels include:

(1) oil produced from shale and tar sands;

(2) gas produced from geopressured brine, Devonian shale, coal seams, tight formations ("tight sands"), or biomass; and

(3) liquid, gaseous, or solid synthetic fuels produced from coal (including lignite).

In general, the credit is available only with respect to fuels produced from wells drilled or facilities placed in service after December 31, 1979, and before January 1, 1993. An exception extends the January 1, 1993 expiration date for facilities producing gas from biomass and synthetic fuel from coal if the facility producing the fuel is placed in service before July 1, 1998, pursuant to a binding contract entered into before January 1, 1997.

The credit may be claimed for qualified fuels produced and sold before January 1, 2003 (in the case of non-conventional sources subject to the January 1, 1993 expiration date) or January 1, 2008 (in the case of biomass gas and synthetic fuel facilities eligible for the extension period).

Description of Proposal

The proposal would permit taxpayers to claim credit on qualifying liquid, gaseous, or solid synthetic fuels produced from coal (including lignite) from facilities placed in service after date of enactment and before January 1, 2007. A qualifying fuel is a fuel that when burned emits 20 percent less SO_2 and nitrogen oxides than the burning of feedstock coal or comparable coal predominantly available in the marketplace as of January 1, 2002, and if the fuel sells at prices at least 50 percent greater than the prices of the feedstock coal or comparable coal. However, no fuel produced from an advanced clean coal facility (as defined in Part IV.A) would qualify as qualifying fuel. The amount of credit would be $3.00 per barrel equivalent. The credit would be allowed for fuel produced during the five-year period beginning on the date the facility is placed in service.

Effective Date

The proposal would be effective for fuel sold after the date of enactment.

K. Natural Gas Distribution Lines Treated as Fifteen-Year Property

Present Law

The applicable recovery period for assets placed in service under the Modified Accelerated Cost Recovery System is based on the "class life of the property." The class lives of assets placed in service after 1986 are generally set forth in Revenue Procedure 87-56.[16] Natural gas distribution pipelines are assigned a 20-year recovery period and a class life of 35 years.

Description of Proposal

The proposal would establish a statutory 15-year recovery period and a class life of 20 years for natural gas distribution lines.

Effective Date

The proposal would be effective for property placed in service after the date of enactment.

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[16] 1987-2 C.B. 674 (as clarified and modified by Rev. Proc. 88-22, 1988-1 C.B. 785).

VI. PROVISIONS RELATING TO ELECTRIC INDUSTRY RESTRUCTURING

The ultimate structure of the electric service industry when the currently anticipated overall industry restructuring is completed remains highly speculative at the present time. For example, the extent to which transmission activities will be consolidated into regional transmission organizations and the structure of those organizations has not been resolved. In particular, representatives of the Federal Energy Regulatory Commission ("FERC") have stated that FERC is *encouraging* formation of separate regional transmission organizations, but is not *requiring* utilities to divest themselves fully of ownership of their transmission assets when the utilities participate in such arrangements. Further, the role of public power entities, including the extent to which and the circumstances under which these entities legally or economically may be required to participate in open access arrangements, is unresolved.

The proposal recognizes that it is not possible at the present time to design tax provisions that will address an as yet undefined legal and economic industry structures. The proposal would put in place a mechanism to ensure that up-to-date information on tax issues that arise from future developments is available to the Congress so that appropriate changes to the tax law can be considered on a timely basis.

Further, on January 18, 2001, the Treasury Department published temporary and proposed regulations to provide guidance to issuers of governmental bonds for electric output facilities ("the regulations"). The regulations provide significant interim relief for outstanding electric output facility bonds. Because of this interim relief and the aforementioned uncertainty regarding future industry structure, the proposal does not address issues related to issuance of tax-exempt bonds. The proposal does, however, address certain aspects of electric industry restructuring that are known at the present time and for which comparable interim regulatory relief has not been provided -- issues relating to certain transfers of nuclear decommissioning plants by investor-owned utilities ("IOUs") and certain transactions engaged in by rural electric cooperatives.

A. Ongoing Study and Reports With Regard to Tax Issues Resulting from Future Restructuring Decisions

The proposal would direct the Department of the Treasury (in consultation with FERC) to conduct an ongoing study of tax issues resulting from restructuring of the electric service industry. The Treasury would be directed to report to Congress at least annually, no later than December 31, on tax issues identified since its last report. The first report would be due no later than December 31, 2002. These annual reports would continue until such time as the industry restructuring activities contemplated under the legislation in conjunction with which the proposal is to be considered have been completed.

Among other issues, this ongoing study would be expected to focus on the effect of restructuring on IOU's and cooperatives (e.g., asset divestitures). In addition, the proposal anticipates that the Treasury Department as part of the analysis underlying its ongoing study would review the interim relief provided to certain tax-exempt bonds in the regulations described above. As current uncertainties regarding the electric service industry are resolved, the proposal

anticipates that the Treasury would, in an expeditious manner, adopt regulatory provisions that are consistent with its current regulatory authority under the Code. Where changes in the private business use rules are determined to require legislation, the proposal anticipates that the Treasury would include recommendations on such changes in its annual reports to Congress.

B. Modification to Special Rules for Nuclear Decommissioning Costs

Present Law

Overview

Special rules dealing with nuclear decommissioning reserve funds were adopted by Congress in the Deficit Reduction Act of 1984 ("1984 Act"), when tax issues regarding the time value of money were addressed generally. Under general tax accounting rules, a deduction for accrual basis taxpayers is deferred until there is economic performance for the item for which the deduction is claimed. However, the 1984 Act contains an exception under which a taxpayer responsible for nuclear powerplant decommissioning may elect to deduct contributions made to a qualified nuclear decommissioning fund for future decommissioning costs. Taxpayers who do not elect this provision are subject to general tax accounting rules.

Qualified nuclear decommissioning fund

A qualified nuclear decommissioning fund (a "qualified fund") is a segregated fund established by a taxpayer that is used exclusively for the payment of decommissioning costs, taxes on fund income, management costs of the fund, and for making investments. The income of the fund is taxed at a reduced rate of 20 percent for taxable years beginning after December 31, 1995.[17]

Contributions to a qualified fund are deductible in the year made to the extent that these amounts were collected as part of the cost of service to ratepayers (the "cost of service requirement").[18] Funds withdrawn by the taxpayer to pay for decommissioning costs are included in the taxpayer's income, but the taxpayer also is entitled to a deduction for decommissioning costs as economic performance for such costs occurs.

Accumulations in a qualified fund are limited to the amount required to fund decommissioning costs of a nuclear powerplant for the period during which the qualified fund is in existence (generally post-1984 decommissioning costs of a nuclear powerplant). For this purpose, decommissioning costs are considered to accrue ratably over a nuclear powerplant's estimated useful life. In order to prevent accumulations of funds over the remaining life of a nuclear powerplant in excess of those required to pay future decommissioning costs of such nuclear powerplant and to ensure that contributions to a qualified fund are not deducted more

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[17] As originally enacted in 1984, a qualified fund paid tax on its earnings at the top corporate rate and, as a result, there was no present-value tax benefit of making deductible contributions to a qualified fund. Also, as originally enacted, the funds in the trust could be invested only in certain low risk investments. Subsequent amendments to the provision have reduced the rate of tax on a qualified fund to 20 percent and removed the restrictions on the types of permitted investments that a qualified fund can make.

[18] Taxpayers are required to include in gross income customer charges for decommissioning costs (sec. 88).

rapidly than level funding (taking into account an appropriate discount rate), taxpayers must obtain a ruling from the IRS to establish the maximum annual contribution that may be made to a qualified fund (the "ruling amount"). In certain instances (e.g., change in estimates), a taxpayer is required to obtain a new ruling amount to reflect updated information.

A qualified fund may be transferred in connection with the sale, exchange or other transfer of the nuclear powerplant to which it relates. If the transferee is a regulated public utility and meets certain other requirements, the transfer will be treated as a nontaxable transaction. No gain or loss will be recognized on the transfer of the qualified fund and the transferee will take the transferor's basis in the fund.[19] The transferee is required to obtain a new ruling amount from the IRS or accept a discretionary determination by the IRS.[20]

Nonqualified nuclear decommissioning funds

Federal and State regulators may require utilities to set aside funds for nuclear decommissioning costs in excess of the amount allowed as a deductible contribution to a qualified fund. In addition, taxpayers may have set aside funds prior to the effective date of the qualified fund rules.[21] The treatment of amounts set aside for decommissioning costs prior to 1984 varies. Some taxpayers may have received no tax benefit while others may have deducted such amounts or excluded such amounts from income. Since 1984, taxpayers have been required to include in gross income customer charges for decommissioning costs (sec. 88), and a deduction has not been allowed for amounts set aside to pay for decommissioning costs except through the use of a qualified fund. Income earned in a nonqualified fund is taxable to the fund's owner as it is earned.

Description of Proposal

Repeal of cost of service requirement

The proposal would repeal the cost of service requirement for deductible contributions to a nuclear decommissioning fund. Thus, all taxpayers, including unregulated taxpayers, would be allowed a deduction for amounts contributed to a qualified fund.

Clarify treatment of transfers of qualified funds and deductibility of decommissioning costs

The proposal would clarify the Federal income tax treatment of the transfer of a qualified fund. No gain or loss would be recognized to the transferor or the transferee as a result of the transfer of a qualified fund in connection with the transfer of the power plant with respect to which such fund was established. In addition, the proposal would provide that all nuclear decommissioning costs are deductible when paid.

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[19] Treas. reg. sec. 1.468A-6.

[20] Treas. reg. sec. 1.468A-6(f).

[21] These funds are generally referred to as "nonqualified funds."

Effective Date

The proposal would be effective for taxable years beginning after December 31, 2002.

C. Treatment of Certain Income of Electric Cooperatives

Present Law

In general

Under present law, an entity must be operated on a cooperative basis in order to be treated as a cooperative for Federal income tax purposes. Although not defined by statute or regulation, the two principal criteria for determining whether an entity is operating on a cooperative basis are: (1) ownership of the cooperative by persons who patronize the cooperative; and (2) return of earnings to patrons in proportion to their patronage. The Internal Revenue Service requires that cooperatives must operate under the following principles: (1) subordination of capital to control over the cooperative undertaking and financial benefits from ownership; (2) democratic control by the members of the cooperative; (3) vesting in and allocation among the members of all excess of operating revenues over the expenses incurred to generate revenues in proportion to their participation in the cooperative (patronage); and (4) operation at cost (not operating for profit or below cost).[22]

In general, cooperative members are those who participate in the management of the cooperative and who share in patronage capital. As described below, income from the sale of electric energy by an electric cooperative may be member or non-member income to the cooperative, depending on the membership status of the purchaser. A municipal corporation may be a member or non-member of a cooperative.

For Federal income tax purposes, a cooperative generally computes its income as if it were a taxable corporation, with one exception--the cooperative may exclude from its taxable income distributions of patronage dividends. In general, patronage dividends are the profits of the cooperative that are rebated to its patrons pursuant to a pre-existing obligation of the cooperative to do so. The rebate must be made in some equitable fashion on the basis of the quantity or value of business done with the cooperative.

Except for tax-exempt farmers' cooperatives, cooperatives that are subject to the cooperative tax rules of subchapter T of the Code (sec. 1381, *et seq.*) are permitted a deduction for patronage dividends from their taxable income only to the extent of net income is derived from transactions with patrons who are members of the cooperative (sec. 1382). The availability of such deductions from net income has the effect of allowing the cooperative to be treated like a conduit with respect to profits derived from transactions with patrons who are members of the cooperative.

Cooperatives that qualify as tax-exempt farmers' cooperatives are permitted to exclude patronage dividends from their taxable income to the extent of all net income, including net income derived from transactions with patrons who are not members of the cooperative,

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[22] Announcement 96-24, Proposed Examination Guidelines Regarding Rural Electric Cooperatives, 1996-16 I.R.B. 35.

provided the value of transactions with patrons who are not members of the cooperative does not exceed the value of transaction with patrons who are members of the cooperative (sec. 521).

Taxation of electric cooperatives exempt from subchapter T

In general, the cooperative tax rules of subchapter T apply to any corporation operating on a cooperative basis (except mutual savings banks, insurance companies, other tax-exempt organizations, and certain utilities), including tax-exempt farmers' cooperatives (described in sec. 521(b)). However, subchapter T does not apply to an organization that is "engaged in furnishing electric energy, or providing telephone service, to persons in rural areas" (sec. 1381(a)(2)(C)). Instead, electric cooperatives are taxed under rules that were generally applicable to cooperatives prior to the enactment of subchapter T in 1962. Under these rules, an electric cooperative can exclude patronage dividends from taxable income to the extent of all net income of the cooperative, including net income derived from transactions with patrons who are not members of the cooperative.[23]

Tax exemption of rural electric cooperatives

Section 501(c)(12) provides an income tax exemption for rural electric cooperatives if at least 85 percent of the cooperative's income consists of amounts collected from members for the sole purpose of meeting losses and expenses of providing service to its members. The Internal Revenue Service takes the position that rural electric cooperatives also must comply with the fundamental cooperative principles described above in order to qualify for tax exemption under section 501(c)(12).[24] The 85-percent test is determined without taking into account any income from qualified pole rentals and cancellation of indebtedness income from the prepayment of a loan under sections 306A, 306B, or 311 of the Rural Electrification Act of 1936 (as in effect on January 1, 1987). The exclusion for cancellation of indebtedness income applies to such income arising in 1987, 1988, or 1989 on debt that either originated with, or is guaranteed by, the Federal Government. Rural electric cooperatives generally are subject to the tax on unrelated trade or business income under Code section 511.

Description of Proposal

Treatment of income from open access transactions

The proposal would provide that income received or accrued by a rural electric cooperative from any "open access transaction" (other than income received or accrued directly or indirectly from a member of the cooperative) is excluded in determining whether a rural electric cooperative satisfies the 85-percent test for tax exemption under section 501(c)(12). The term "open access transaction" is defined as any activity that would be a "permitted open access activity".

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[23] *See* Rev. Rul. 83-135, 1983-2 C.B. 149.

[24] Rev. Rul. 72-36, 1972-1 C.B. 151.

As applied to rural electric cooperatives, the term "permitted open access activity" is defined as--

(1) the provision or sale of transmission services or ancillary services on a nondiscriminatory open access basis: (i) pursuant to an open access transmission tariff filed with and approved by the Federal Energy Regulatory Commission ("FERC") (including acceptable reciprocity tariffs), but only if (in the case of a voluntarily filed tariff) the cooperative files a report with FERC within 90 days of enactment of this provision relating to whether or not the cooperative will join a regional transmission organization ("RTO"); or (ii) under an RTO agreement approved by FERC (including an agreement providing for the transfer of control--but not ownership--of transmission facilities);[25]

(2) the provision or sale of electric energy distribution services or ancillary services on a nondiscriminatory open access basis to end-users served by distribution facilities owned by the cooperative or its members;

(3) the delivery or sale of electric energy on a nondiscriminatory open access basis, provided that such electric energy is generated by a generation facility that is directly connected to distribution facilities owned by the cooperative (or its members) which owns the generation facility.

For purposes of the 85-percent test, the proposal also would provide that income received or accrued by a rural electric cooperative from any "open access transaction" is treated as an amount collected from members for the sole purpose of meeting losses and expenses, for purposes of the 85-percent test, if the income is received or accrued indirectly from a member of the cooperative.

Treatment of income from nuclear decommissioning transactions

The proposal would provide that income received or accrued by a rural electric cooperative from any "nuclear decommissioning transaction" also is excluded in determining whether a rural electric cooperative satisfies the 85-percent test for tax exemption under section 501(c)(12). The term "nuclear decommissioning transaction" is defined as--

(1) any transfer into a trust, fund, or instrument established to pay any nuclear decommissioning costs if the transfer is in connection with the transfer of the cooperative's interest in a nuclear powerplant or nuclear powerplant unit;

(2) any distribution from a trust, fund, or instrument established to pay any nuclear decommissioning costs; or

(3) any earnings from a trust, fund, or instrument established to pay any nuclear decommissioning costs.

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[25] Under this provision, references to FERC would be treated as including references to the Public Utility Commission of Texas or the Rural Utilities Service.

Treatment of income from asset exchange or conversion transactions

The proposal would provide that gain realized by a tax-exempt rural electric cooperative from a voluntary exchange or involuntary conversion of certain property is excluded in determining whether a rural electric cooperative satisfies the 85-percent test for tax exemption under section 501(c)(12). This provision only applies to the extent that: (1) the gain qualifies for deferred recognition under section 1031 (relating to exchanges of property held for productive use or investment) or section 1033 (relating to involuntary conversions); and (2) the replacement property that is acquired by the cooperative pursuant to section 1031 or section 1033 (as the case may be) constitutes property that is used, or to be used, either for the purpose of generating, transmitting, distributing, or selling electricity, or for the purpose of producing, transmitting, distributing, or selling natural gas.

Treatment of cancellation of indebtedness income from prepayment of certain loans

The proposal would provide that income from the prepayment of any loan, debt, or obligation of a tax-exempt rural electric cooperative that is originated, insured, or guaranteed by the Federal Government under the Rural Electrification Act of 1936 is excluded in determining whether the cooperative satisfies the 85-percent test for tax exemption under section 501(c)(12).

Treatment of income from load loss transactions

Tax-exempt rural electric cooperatives--The proposal would provide that income received or accrued by a tax-exempt rural electric cooperative from a "load loss transaction" is treated under 501(c)(12) as income collected from members for the sole purpose of meeting losses and expenses of providing service to its members. Therefore, income from load loss transactions would be treated as member income in determining whether a rural electric cooperative satisfies the 85-percent test for tax exemption under section 501(c)(12). The proposal also would provide that income from load loss transactions does not cause a rural electric cooperative to fail to be treated for Federal income tax purposes as a mutual or cooperative company under the fundamental cooperative principles described above.

The term "load loss transaction" would be defined as any wholesale or retail sale of electric energy (other than to a member of the cooperative) to the extent that the aggregate amount of such sales during a seven-year period beginning with the "start-up year" does not exceed the reduction in the amount of sales of electric energy for each year of such period by the cooperative to members. The "start-up year" is defined as the first year: (1) that the cooperative offers nondiscriminatory open access; or (2) in which at least 10 percent of the cooperative's sales of electric energy are to patrons who are not members of the cooperative.

The proposal also would exclude income received or accrued by rural electric cooperatives from load loss transactions from the tax on unrelated trade or business income.

Taxable electric cooperatives--The proposal would provide that similar rules apply to the receipt or accrual of income from load loss transactions of taxable electric cooperatives. For example, income from a load loss transaction would be excludible from the taxable income of a taxable electric cooperative if the cooperative distributes such income pursuant to a pre-existing contract to distribute the income to a patron who is not a member of the cooperative.

Effective Date

The proposal would be effective for taxable years beginning after the date of enactment.

VII. EXTENSION OF TAX INCENTIVES FOR INDIAN RESERVATIONS

A. Extension of Accelerated Depreciation and Wage Credit Benefits on Indian Reservations

Present Law

Present law includes the following tax incentives for businesses located within Indian reservations.

Accelerated depreciation

With respect to certain property used in connection with the conduct of a trade or business within an Indian reservation, depreciation deductions under section 168(j) will be determined using the following recovery periods:

3-year property	2 years
5-year property	3 years
7-year property	4 years
10-year property	6 years
15-year property	9 years
20-year property	12 years
Nonresidential real property	22 years

"Qualified Indian reservation property" eligible for accelerated depreciation includes property which is (1) used by the taxpayer predominantly in the active conduct of a trade or business within an Indian reservation, (2) not used or located outside the reservation on a regular basis, (3) not acquired (directly or indirectly) by the taxpayer from a person who is related to the taxpayer (within the meaning of section 465(b)(3)(C)), and (4) described in the recovery-period table above. In addition, property is not "qualified Indian reservation property" if it is placed in service for purposes of conducting gaming activities. Certain "qualified infrastructure property" may be eligible for the accelerated depreciation even if located outside an Indian reservation, provided that the purpose of such property is to connect with qualified infrastructure property located within the reservation (e.g., roads, power lines, water systems, railroad spurs, and communications facilities).

The depreciation deduction allowed for regular tax purposes is also allowed for purposes of the alternative minimum tax. The accelerated depreciation for Indian reservations is available with respect to property placed in service on or after January 1, 1994, and before January 1, 2004.

Indian employment credit

In general, a credit against income tax liability is allowed to employers for the first $20,000 of qualified wages and qualified employee health insurance costs paid or incurred by the employer with respect to certain employees (sec. 45A). The credit is equal to 20 percent of the

excess of eligible employee qualified wages and health insurance costs during the current year over the amount of such wages and costs incurred by the employer during 1993. The credit is an incremental credit, such that an employer's current-year qualified wages and qualified employee health insurance costs (up to $20,000 per employee) are eligible for the credit only to the extent that the sum of such costs exceeds the sum of comparable costs paid during 1993. No deduction is allowed for the portion of the wages equal to the amount of the credit.

Qualified wages means wages paid or incurred by an employer for services performed by a qualified employee. A qualified employee means any employee who is an enrolled member of an Indian tribe or the spouse of an enrolled member of an Indian tribe, who performs substantially all of the services within an Indian reservation, and whose principal place of abode while performing such services is on or near the reservation in which the services are performed. An employee will not be treated as a qualified employee for any taxable year of the employer if the total amount of wages paid or incurred by the employer with respect to such employee during the taxable year exceeds an amount determined at an annual rate of $30,000 (adjusted for inflation after 1993).

The wage credit is available for wages paid or incurred on or after January 1, 1994, in taxable years that begin before December 31, 2003.

Description of Proposal

Accelerated depreciation

The proposal would extend the accelerated depreciation incentive for two years (to property placed in service before January 1, 2006).

Indian employment credit

The proposal would extend the Indian employment credit incentive for two years (to taxable years beginning before January 1, 2006).

Effective Date

The proposal would be effective on the date of enactment.

B

SECURITIES AND EXCHANGE COMMISSION

WASHINGTON, D.C. 20549

FORM 10-K

(Mark One)

☒ **ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**
For the fiscal year ended December 31, 2000

OR

☐ **TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**
For the transition period from _____ to _____
Commission File Number 1-8962

PINNACLE WEST CAPITAL CORPORATION

(Exact name of registrant as specified in its charter)

ARIZONA (State or other jurisdiction of incorporation or organization)	86-0512431 (I.R.S. Employer Identification No.)
400 North Fifth Street, P.O. Box 53999 Phoenix, Arizona 85072-3999 (Address of principal executive offices, including zip code)	(602) 250-1000 (Registrant's telephone number, including area code)

Securities registered pursuant to Section 12(b) of the Act:

Title Of Each Class	Name Of Each Exchange On Which Registered
Common Stock, No Par Value	New York Stock Exchange Pacific Stock Exchange

Title Of Each Class Of Voting Stock	Shares Outstanding As Of March 8, 2001	Aggregate Market Value Of Shares Held By Non-Affiliates As Of March 8, 2001
Common Stock, No Par Value	84,727,490	$3,944,064,660(a)

(a) Computed by reference to the closing price on the composite tape on March 8, 2001, as reported by the Wall Street Journal.

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. Yes X No __

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K is not contained herein, and will not be contained, to the best of registrant's knowledge, in any amendment to this Form 10-K. [ ]

DOCUMENTS INCORPORATED BY REFERENCE

Portions of the registrant's definitive Proxy Statement relating to its Annual Meeting of Shareholders to be held on May 23, 2001 are incorporated by reference into Part III hereof.

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GLOSSARY

ACC – Arizona Corporation Commission

ACC Staff – Staff of the Arizona Corporation Commission

AFUDC –allowance for funds used during construction

AISA – Arizona Independent Scheduling Administrator

ANPP – Arizona Nuclear Power Project, also known as Palo Verde

APS – Arizona Public Service Company, a subsidiary of the Company

APSES – APS Energy Services Company, Inc., a subsidiary of the Company

Cholla – Cholla Power Plant

Cholla 4 – Unit 4 of the Cholla Power Plant

Citizens – Citizens Communications Company

Company – Pinnacle West Capital Corporation

CPUC – California Public Utility Commission

DIG – Derivatives Implementation Group

DOE – United States Department of Energy

EITF – Emerging Issues Task Force

El Dorado – El Dorado Investment Company, a subsidiary of the Company

EPA – United States Environmental Protection Agency

ERMC – Energy Risk Management Committee

FASB – Financial Accounting Standards Board

FERC – United States Federal Energy Regulatory Commission

FIP – Federal Implementation Plan

Four Corners – Four Corners Power Plant

GAAP –generally accepted accounting principles in the United States of America

ISO – California Independent System Operator

ITC –investment tax credit

KW – kilowatt, one thousand watts

KWh –kilowatt-hour, one thousand watts per hour

MW – megawatt, one million watts

MWh –megawatt-hours, one million watts per hour

1992 Energy Act – National Energy Policy Act of 1992

NPC – Nevada Power Company

NPUC – Nevada Public Utility Commission

NRC – United States Nuclear Regulatory Commission

Nuclear Waste Act – Nuclear Waste Policy Act of 1982, as amended

Palo Verde – Palo Verde Nuclear Generating Station

PG&E – PG&E Corp.

Pinnacle West Energy – Pinnacle West Energy Corporation, a subsidiary of the Company

PX – California Power Exchange

RTO – Regional Transmission Organization

Rules – ACC retail electric competition rules

Salt River Project – Salt River Project Agricultural Improvement and Power District

SCE – Southern California Edison

SFAS – Statement of Financial Accounting Standards

SunCor – SunCor Development Company, a subsidiary of the Company

PART I

ITEM 1. BUSINESS

Overview of Our Business

We were incorporated in 1985 under the laws of the State of Arizona and own all of the outstanding common stock of APS. APS is Arizona's largest electric utility and provides retail and wholesale electric service to the entire state with the exception of Tucson and about one-half of the Phoenix area. APS also generates and, directly or through our power marketing division, sells and delivers electricity to wholesale customers in the western United States.

Our other major subsidiaries are:

- Pinnacle West Energy, through which we intend to conduct our unregulated generation operations;
- APS Energy Services, which sells energy and energy-related products and services in competitive retail markets in the western United States;
- SunCor, which is a developer of residential, commercial, and industrial real estate projects in Arizona, New Mexico, and Utah; and
- El Dorado, which is primarily a venture capital and investment firm.

We discuss each of these subsidiaries in greater detail below.

At December 31, 2000, we employed about 7,200 people, including the employees of our subsidiaries. Of these employees, 5,300 were employees of our major subsidiary, APS, and employees assigned to joint projects of APS where APS serves as project manager. About 1,900 people were employed by the parent company and our other subsidiaries. Our principal executive offices are located at 400 North Fifth Street, Phoenix, Arizona 85004 (telephone 602-250-1000).

See "Financial Review – Business Segments" in Item 7 and Note 18 of Notes to Consolidated Financial Statements in Item 8 for a discussion of our business segments.

Forward-Looking Statements

This document contains forward-looking statements based on current expectations and we assume no obligation to update these statements. Because actual results may differ materially from expectations, we caution readers not to place undue reliance on these statements. A number of factors could cause future results to differ materially from historical results, or from results or outcomes currently expected or sought by us. These factors include the ongoing restructuring of the electric industry; the outcome of regulatory and legislative proceedings relating to the restructuring; regional economic and market conditions, including the California energy situation, which could affect customer growth and the cost of power supplies; the cost of debt and equity capital; weather variations affecting local and regional customer energy usage; conservation programs; the successful completion of our generation expansion program; regulatory issues associated with generation

expansion, such as permitting and licensing; our ability to compete successfully outside traditional regulated markets (including the wholesale market); technological developments in the electric industry; and the strength of the stock market (particularly the technology sector in which El Dorado is currently invested) and the real estate market in SunCor's market areas, which include Arizona, New Mexico and Utah.

BUSINESS OF ARIZONA PUBLIC SERVICE COMPANY

Following is a discussion of the business of APS, our major subsidiary.

General

APS was incorporated in 1920 under the laws of Arizona and is Arizona's largest electric utility, with more than 850,000 customers. APS provides wholesale or retail electric service to the entire state of Arizona, with the exception of Tucson and about one-half of the Phoenix area. APS also generates and, directly or through our power marketing division, sells and delivers electricity to wholesale customers in the western United States. During 2000, no single purchaser or user of energy accounted for more than 3.5% of total electric revenues.

At December 31, 2000, APS employed 5,300 people, which includes employees assigned to joint projects where APS is project manager. APS' principal executive offices are located at 400 North Fifth Street, Phoenix, Arizona 85004 (telephone 602-250-1000).

Regulation and Competition

Retail

The ACC regulates APS' retail electric rates and its issuance of securities. The ACC must also approve any transfer of APS' utility property and transactions between APS and affiliated parties. See "Financial Review – Business Outlook – Competition and Industry Restructuring" in Item 7 and Note 3 of Notes to Consolidated Financial Statements in Item 8 for a discussion of electric industry restructuring in Arizona, including APS' 1999 Settlement Agreement, the ACC retail electric competition rules, and the legal challenges to both the 1999 Settlement Agreement and the Rules.

Although the Rules allow retail customers to have access to competitive providers of energy and energy services, APS is the "provider of last resort" for standard offer customers under rates that have been approved by the ACC. These rates are fixed until July 1, 2004. The 1999 Settlement Agreement allows APS to seek adjustment of these rates in the event of emergency conditions or circumstances, such as the inability to secure financing on reasonable terms, or material changes in APS' cost of service for ACC-regulated services resulting from federal, tribal, state or local laws, regulatory requirements, judicial decisions, actions or orders. Energy prices in the western wholesale market vary and, during the course of the last year, have been volatile. At various times, prices in the spot wholesale market have significantly exceeded the amount included in APS' current retail rates. APS expects these market conditions to continue in 2001. We believe we have adequately supplemented our current generation portfolio with power purchased through contracts and hedging techniques that limit exposure to the volatile spot wholesale power market. However, in the event of shortfalls due to unforeseen increases in load demand or generation outages, we may need to purchase additional supplemental power in the wholesale spot market. Unless APS is able to obtain

an adjustment of its rates under the 1999 Settlement Agreement, there can be no assurance that APS would be able to fully recover the costs of this power.

As discussed in "Financial Review – Electric Competition (Retail)" in Item 7 and in Note 3 of Notes to Consolidated Financial Statements in Item 8, the 1999 Settlement Agreement authorizes APS to transfer its competitive generation assets and services to one or more corporate affiliates no later than December 31, 2002. APS intends to move its generation assets to Pinnacle West Energy within that timeframe. Following its receipt of these generation assets, Pinnacle West Energy expects to sell its power at wholesale to our power marketing division (Power Marketing). Power Marketing, in turn, is expected to sell power to APS and to non-affiliated power purchasers. APS is expected to meet fifty percent of its energy needs under a power purchase agreement with Power Marketing. As required by the Rules, APS will acquire the remaining fifty percent of its energy needs through a competitive bid process in which Power Marketing may participate. We believe that these arrangements will allow us to manage APS' exposure to the wholesale power market during the period within which APS' rates are fixed, as discussed in the preceding paragraph.

In addition to the introduction of competition pursuant to the 1999 Settlement Agreement and the Rules, APS is subject to varying degrees of competition from other utilities in its region (such as Tucson Electric Power Company, Southwest Gas Corporation, and Citizens Communications Company) as well as cooperatives, municipalities, electrical districts, and similar types of governmental organizations (principally Salt River Project). APS also faces competition from low-cost hydroelectric power and parties that have access to preferential low-priced federal power and other subsidies. In addition, some customers, particularly industrial and large commercial customers, may own and operate facilities to generate their own electric energy requirements.

Wholesale

We compete with other utilities, power marketers, and independent power producers in the sale of electric capacity and energy in the wholesale market. We expect competition in the wholesale market will remain vigorous. The FERC regulates rates for wholesale power sales and transmission services. During 2000, approximately 46% of our electric operating revenues resulted from such sales and services. APS transferred the wholesale power marketing function to the parent company during 2000.

See "Financial Review – Capital Resources and Cash Requirements – Pinnacle West Energy" and Note 12 of Notes to Consolidated Financial Statements for information regarding generation expansion plans.

The 1992 Energy Act and the FERC's rulemaking activities have established the regulatory framework to open the wholesale energy market to competition. The 1992 Energy Act permits utilities to develop independent electric generating plants for sales to wholesale customers, and authorizes the FERC to order transmission access for third parties to transmission facilities owned by another entity. The 1992 Energy Act does not, however, permit the FERC to require transmission access to retail customers. Open-access transmission for wholesale customers provides energy suppliers, including us, with opportunities to sell and deliver electricity at market-based prices.

On December 20, 1999, the FERC issued its Order No. 2000 regarding Regional Transmission Organizations (RTO). In its order, the FERC stressed the voluntary nature of RTO participation by utilities and set minimum characteristics and functions that must be met by utilities that participate in RTOs. The order provides for an open, flexible structure for RTOs to meet the needs of the market, and provides for the possibility of incentive ratemaking and other benefits for utilities that participate in an RTO.

The characteristics for an acceptable RTO include independence from market participants, operational control over a region large enough to support efficient and nondiscriminatory markets, and exclusive authority to maintain short-term reliability. As required by the FERC order, APS, along with several neighboring transmission owners located in the southwestern United States, filed a report with the FERC on October 16, 2000 that detailed the progress in establishing an RTO that would be responsible for ensuring transmission reliability and nondiscriminatory access to the regional transmission grid. APS expects that Desert STAR, the non-profit corporation named in the filing, will make additional filings with the FERC in the near future to establish itself as an RTO for the region.

See "Financial Review – Business Outlook – California Energy Market Issues" in Item 7 for a discussion of the energy situation in California.

The ACC retail electric competition rules require the formation and implementation of an Arizona Independent Scheduling Administrator Association. The AISA is anticipated to be a temporary organization until the formation and implementation of an independent system operator or RTO. APS, as an "Affected Utility" under the Rules, participated in the creation of the AISA. Recently, the board of AISA approved a set of operating protocols that have been filed with the FERC. The operating protocols were partially rejected and the remainder are currently under review.

See "Financial Review – Business Outlook – Competition and Industry Restructuring" in Item 7 and Note 3 of Notes to Consolidated Financial Statements in Item 8 for additional information about the ACC Rules and the legal challenges to the Rules.

Regulatory Assets

Our major regulatory assets are deferred income taxes and rate synchronization cost deferrals. As a result of our 1999 Settlement Agreement, we discontinued the application of SFAS No. 71, "Accounting for the Effects of Certain Types of Regulation," for our generation operations. As a result, we tested the generation assets for impairment and determined that the generation assets were not impaired. Pursuant to the 1999 Settlement Agreement, we reported a regulatory disallowance ($140 million after income taxes) as an extraordinary charge on the 1999 income statement. Prior to the 1999 Settlement Agreement, under a 1996 regulatory agreement, the ACC accelerated the amortization of substantially all of our regulatory assets to an eight-year period that would have ended June 30, 2004. The regulatory assets to be recovered under the 1999 Settlement Agreement are being amortized pursuant to a revised amortization schedule. See Notes 1, 3, and 10 of Notes to Consolidated Financial Statements in Item 8 for additional information.

Generating Fuel and Purchased Power

2000 Energy Mix

APS' sources of energy during 2000 were: purchased power – 46.0% (approximately 88% of which was for wholesale power operations); coal – 27.9%; nuclear – 19.8%; gas – 6.0%; and other (includes oil, hydro and solar) – 0.3%.

Coal Supply

Cholla APS purchases most of Cholla's coal requirements from a coal supplier who mines all of the coal under a long-term lease of coal reserves owned by the Navajo Nation, the federal government, and private landholders. Cholla has sufficient coal under current contracts to ensure a reliable fuel supply through 2005. APS purchases a portion of Cholla's coal requirements on the spot market to take advantage of competitive pricing options. Following expiration of current contracts, APS believes that numerous competitive fuel supply options will exist to ensure continuous plant operation. We expect the current supplier to continue to provide most of Cholla's low sulfur coal requirements through the current contract. APS believes that there are sufficient reserves of low sulfur coal available from other suppliers to ensure the continued operation of Cholla for its useful life.

Four Corners APS purchases all of Four Corners' coal requirements from a coal supplier with a long-term lease of coal reserves owned by the Navajo Nation. Four Corners is under contract for coal through 2004, with options to extend the contract through the plant site lease expiration in 2017. The Four Corners lease waives, until July 2001, the requirement that APS and its fuel supplier pay certain taxes to the Navajo Nation. The coal supplier currently pays a possessory interest tax to the Navajo Nation, which is reimbursed by the Four Corners participants. The coal supplier, the Navajo Nation, and the Four Corners participants agreed to investigate alternative contractual arrangements and business relationships before the expiration of tax waivers in an effort to permit the electricity generated at Four Corners to be priced competitively. APS anticipates that the Navajo Nation will levy additional taxes upon the expiration of the tax waivers; however, APS cannot currently predict the outcome of this matter or the amount of any additional taxes.

Navajo Generating Station The Navajo Generating Station's coal requirements are purchased from a supplier with long-term leases from the Navajo Nation and the Hopi Tribe. The Navajo Generating Station is under contract with its coal supplier through 2011, with options to extend through the plant site lease expiration in 2019. The Navajo Generating Station lease waives certain taxes through the lease expiration in 2019. The lease provides for the potential to renegotiate the coal royalty in 2007 and 2017, which may impact the fuel price.

See "Properties – Accredited Capacity" in Item 2 for information about APS' ownership interest in Cholla, Four Corners, and the Navajo Generating Station. See Note 12 of Notes to Consolidated Financial Statements in Item 8 for information regarding our coal mine reclamation obligations.

Natural Gas Supply

APS purchases the majority of its natural gas requirements under contracts with a number of natural gas suppliers. APS' natural gas supply is transported pursuant to a firm transportation service contract with El Paso Natural Gas Company. We anticipate that the natural gas requirements for our generation expansion plans (see Note 12) will be met with these contracts. We continue to analyze the market to determine the most favorable source and method of meeting our natural gas requirements.

Nuclear Fuel Supply

The fuel cycle for Palo Verde is comprised of the following stages:

- mining and milling of uranium ore to produce uranium concentrates;
- conversion of uranium concentrates to uranium hexafluoride;
- enrichment of uranium hexafluoride;
- fabrication of fuel assemblies;
- utilization of fuel assemblies in reactors; and
- storage and disposal of spent fuel.

The Palo Verde participants have made contractual arrangements to obtain quantities of uranium concentrates anticipated to be sufficient to meet operational requirements through 2002. Spot purchases on the uranium market will be made, as appropriate, in lieu of any uranium that might be obtained through contractual options. Existing uranium concentrates contracts and options could be utilized to meet approximately:

- 77% of requirements in 2003;
- 77% of requirements in 2004;
- 44% of requirements in 2005 through 2007; and
- 16% of requirements in 2008 and beyond.

The Palo Verde participants have contracts and options for uranium conversion services that could be utilized to meet approximately:

- 75% of requirements in 2001; and
- 80% of requirements in 2002.

The Palo Verde participants have an enrichment services contract and an enriched uranium product contract that furnish enrichment services required for the operation of the three Palo Verde units through 2003. In addition, existing contracts will provide fuel assembly fabrication services until at least 2015 for each Palo Verde unit.

APS is currently pursuing several offers to procure the uranium, conversion services and the enrichment services components of nuclear fuel to meet all of Palo Verde's requirements through 2008.

Spent Nuclear Fuel and Waste Disposal Pursuant to the Nuclear Waste Act, the DOE must accept and dispose of all spent nuclear fuel and other high-level radioactive wastes generated by domestic power reactors. The NRC requires operators of nuclear power reactors to enter into spent fuel disposal contracts with the DOE. Under the Nuclear Waste Act, the DOE was to develop a permanent repository for the storage and disposal of spent nuclear fuel by 1998. The DOE has announced that such a permanent repository cannot be completed before 2010, and that it does not intend to begin accepting spent fuel prior to that date.

In November 1997, the United States Court of Appeals for the District of Columbia Circuit (D.C. Circuit) issued a decision precluding the DOE from excusing its own delay, but refused to order the DOE to begin accepting spent nuclear fuel. Based on this decision, a number of utilities filed damages lawsuits against DOE in the Court of Federal Claims. In decisions that became final in December 2000, the United States Court of Appeals for the Federal Circuit held that utilities do not

have to exhaust the DOE administrative claims before filing lawsuits for damages against the DOE in the Court of Federal Claims.

Bills have been introduced in prior sessions of the U.S. Congress contemplating the construction of a central interim storage facility, but no bill has been enacted into law. We cannot currently predict what steps will be taken in this area by the current Congress and the Administration.

Facility funding is a further complication. While all nuclear utilities pay into a so-called nuclear waste fund an amount calculated on the basis of the output of their respective plants, the annual Congressional appropriations for the permanent repository have been for amounts less than the amounts paid into the waste fund (the balance of which is being used for other purposes). According to DOE spokespersons, the fund may now be at a level less than needed to achieve a 2010 operational date for a permanent repository. No funding will be available for a central interim facility until one is authorized by Congress.

APS has existing fuel storage pools at Palo Verde and is in the process of completing construction of a new facility for on-site dry storage of spent fuel. With the existing storage pools and the addition of the new facility, APS believes that spent fuel storage or disposal methods will be available for use by Palo Verde to allow its continued operation through the term of the operating license for each Palo Verde unit. See "Palo Verde Nuclear Generating Station" in Note 12 of Notes to Consolidated Financial Statements in Item 8 for a discussion of interim spent fuel storage costs.

Although some low-level waste has been stored on-site in a low-level waste facility, APS is currently shipping low-level waste to off-site facilities. APS currently believes that interim low-level waste storage methods are or will be available for use by Palo Verde to allow its continued operation and to safely store low-level waste until a permanent disposal facility is available.

APS believes that scientific and financial aspects of the issues of spent fuel and low-level waste storage and disposal can be resolved satisfactorily. However, APS also acknowledges that their ultimate resolution in a timely fashion will require political resolve and action on national and regional scales which APS is less able to predict. APS expects to vigorously protect and pursue its rights related to this matter.

Purchased Power Agreements

In addition to that available from its own generating capacity (see "Properties" in Item 2), APS purchases electricity under various arrangements. One of the most important of these is a long-term contract with Salt River Project. The amount of electricity available to APS is based in large part on customer demand within certain areas now served by APS pursuant to a related territorial agreement. The generating capacity available to APS pursuant to the contract was 322 MW from January through May 2000, and starting June 2000, it changed to 329 MW. In 2000, APS received approximately 1,422,000 MWh of energy under the contract and paid about $76.7 million for capacity availability and energy received. This contract may be canceled by Salt River Project on three years' notice, given no earlier than December 31, 2003. APS may also cancel the contract on five years' notice, given no earlier than December 31, 2006.

In September 1990, APS entered into a thirty-year seasonal capacity exchange agreement with PacifiCorp. Under this agreement, APS receives electricity from PacifiCorp during the summer peak season (from May 15 to September 15) and APS returns electricity to PacifiCorp during the

winter season (from October 15 to February 15). Until 2020, APS and PacifiCorp each has 480 MW per hour of capacity and a related amount of energy available to it under the agreement for their respective seasons. In 2000, APS received approximately 396,000 MWh of energy under the capacity exchange. APS must also make additional offers of energy to PacifiCorp each year through October 31, 2020. Pursuant to this requirement, during 2000, PacifiCorp received offers of 865,800 MWh and purchased about 218,000 MWh.

Construction Program

During the years 1998 through 2000, APS incurred approximately $1.2 billion in capital expenditures. APS' capital expenditures for the years 2001 through 2003 are expected to be primarily for expanding transmission and distribution capabilities to meet growing customer needs, upgrading existing utility property, and for environmental purposes. APS' capital expenditures, including expenditures for environmental control facilities, for the years 2001 through 2003 have been estimated as follows:

(dollars in millions)

By Year		By Major Facilities	
2001	$ 455	Production	$ 226
2002	401	Transmission and Distribution	924
2003	294	Total	$1,150
Total	$1,150		

The amounts for 2001 through 2003 exclude capitalized interest costs and include capitalized property taxes and about $30-$35 million annually (except 2003) for nuclear fuel. APS conducts a continuing review of its construction program. See "Financial Review – Capital Needs and Resources" in Item 7 for additional information.

Mortgage Replacement Fund Requirements

So long as any of its first mortgage bonds are outstanding, APS is required for each calendar year to deposit with the trustee under its mortgage cash in a formularized amount related to net additions to its mortgaged utility plant. APS may satisfy all or any part of this "replacement fund" requirement by using redeemed or retired bonds, net property additions, or property retirements. For 2000, the replacement fund requirement amounted to approximately $149 million. Certain of the bonds APS has issued under the mortgage that are callable prior to maturity are redeemable at their par value plus accrued interest with cash APS deposits in the replacement fund. These call provisions are subject in many cases to a period of time after the original issuance of the bonds during which they may not be so redeemed.

Environmental Matters

EPA Environmental Regulation

Clean Air Act We are subject to a number of requirements under the Clean Air Act. The Clean Air Act addresses, among other things:

- "acid rain";
- visibility in certain specified areas;
- hazardous air pollutants; and
- areas that have not attained national ambient air quality standards.

With respect to "acid rain," the Clean Air Act establishes a system of sulfur dioxide emissions "allowances" to offset each ton of sulfur dioxide emitted by affected power plants. Based on EPA allowance allocations, we will have sufficient allowances to permit continued operation of our plants at current levels without installing additional equipment. The Clean Air Act also requires the EPA to set nitrogen oxides emissions limitations for certain coal-fired units. The EPA rule allows emissions from all units within a plant to be averaged to demonstrate compliance with the emission limitation. Currently, nitrogen oxides emissions from all of our units are within the limitations specified under the EPA's rules. We do not currently expect this rule to have a material impact on our financial position, results of operations, or liquidity.

The Clean Air Act requires the EPA to establish a Grand Canyon Visibility Transport Commission to complete a study on visibility impairment in sixteen "Class I Areas" (large national parks and wilderness areas) on the Colorado Plateau. The Navajo Generating Station, Cholla, and Four Corners are located near several Class I Areas on the Colorado Plateau. The Visibility Commission completed its study and on June 10, 1996 submitted its final recommendations to the EPA.

On April 22, 1999, the EPA announced final regional haze rules. These new regulations require states to submit, by 2008, implementation plans to eliminate all man-made emissions causing visibility impairment in certain specified areas, including Class I Areas in the Colorado Plateau. The 2008 implementation plans must also include consideration and potential application of best available retrofit technology for major stationary sources which came into operation between August 1962 and August 1977, such as the Navajo Generating Station, Cholla, and Four Corners.

The rules allow the nine western states and tribes that participated in the Visibility Commission process to follow an alternate implementation plan and schedule for the Class I Areas considered by the Visibility Commission. Under this option, those states and tribes would submit implementation plans by 2003, which would incorporate certain regional sulfur dioxide emissions milestones for the years 2003, 2008, 2013, and 2018 (which includes the application of best available retrofit technology). If the regional emissions in those years were within those milestones, there would be no further emission reduction requirements, and if they were exceeded, then an emission trading program would be implemented to maintain the emissions within those milestones.

The EPA is currently reviewing an "Annex" to the Visibility Commission recommendations that specifies the regional sulfur dioxide emission milestones. The EPA's approval of the Annex would allow the Visibility Commission states and tribes to pursue the alternate implementation of the regional haze rules through 2018. Any states and tribes that implement this option would have to submit revised implementation plans in 2008 to address visibility in those Class I Areas which were not included in the Visibility Commission process. Because the Annex is not final and Arizona and the Navajo Nation have the discretion to choose between the national or the alternate options, the actual impact on APS cannot be determined at this time.

In July 1997, the EPA promulgated final National Ambient Air Quality Standards for ozone and particulate matter. Pursuant to these rules, the ozone standard is more stringent and a new ambient standard for very fine particles has been established. Congress has enacted legislation that could delay the implementation of regional haze requirements and the particulate matter ambient standard; however, the legislation does not preclude the Visibility Commission states and tribes from implementing the alternate regional haze rules discussed above. A federal court determined that the EPA's promulgation of the National Ambient Air Quality Standards violated the constitutional prohibition on delegation of legislative power. The court remanded the ozone standard, vacated the particulate matter standard, and invited the parties that challenged the standards to brief the court on vacating or remanding the very fine particulates standard. On February 27, 2001, the U.S. Supreme Court overruled the federal court's ruling. The Court further held that the EPA could not consider the cost of reducing harmful emissions when setting air quality standards. However, the Court found the EPA implementation policy for the revised ozone standards to be unlawful, and remanded this issue for consideration along with the other preserved challenges to the National Ambient Air Quality Standards. Because the actual level of emissions controls, if any, for any unit cannot be determined at this time, APS currently cannot estimate the capital expenditures, if any, which would result from the final rules. However, APS does not currently expect these rules to have a material adverse effect on its financial position, results of operations, or liquidity.

With respect to hazardous air pollutants emitted by electric utility steam generating units, the EPA recently determined that mercury emissions and other hazardous air pollutants from coal and oil-fired power plants will be regulated. We expect that the EPA will propose specific rules for this purpose in 2003 and finalize them by 2004, with compliance required by 2008. Because the ultimate requirements that the EPA may impose are not yet known, we cannot currently estimate the capital expenditures, if any, which may be required.

Certain aspects of the Clean Air Act may require APS to make related expenditures, such as permit fees. APS does not expect any of these expenditures to have a material impact on its financial position, results of operations, or liquidity.

Federal Implementation Plan In September 1999, the EPA proposed a FIP to set air quality standards at certain power plants, including the Navajo Generating Station and Four Corners. The comment period on this proposal ended in November 1999. The FIP is similar to current Arizona regulation of the Navajo Generating Station and New Mexico regulation of Four Corners, with minor modifications. APS does not currently expect the FIP to have a material impact on its financial position, results of operations, or liquidity.

Superfund The Comprehensive Environmental Response, Compensation, and Liability Act (Superfund) establishes liability for the cleanup of hazardous substances found contaminating the soil, water, or air. Those who generated, transported, or disposed of hazardous substances at a contaminated site are among those who are potentially responsible parties. PRPs may be strictly, and often jointly and severally, liable for the cost of any necessary remediation of the substances. The EPA had previously advised APS that the EPA considers APS to be a PRP in the Indian Bend Wash Superfund Site, South Area. APS' Ocotillo Power Plant is located in this area. APS is in the process of conducting an investigation to determine the extent and scope of contamination at the plant site. Based on the information to date, including available insurance coverage and an EPA estimate of cleanup costs, APS does not expect this matter to have a material impact on its financial position, results of operations, or liquidity.

Manufactured Gas Plant Sites APS is currently investigating properties which it now owns or which were at one time owned by it or its corporate predecessors, that were at one time sites of, or sites associated with, manufactured gas plants. The purpose of this investigation is to determine if:

- waste materials are present;
- such materials constitute an environmental or health risk; and
- APS has any responsibility for remedial action.

Where appropriate, APS has begun remediation of certain of these sites. APS does not expect these matters to have a material adverse effect on its financial position, results of operations, or liquidity.

Purported Navajo Environmental Regulation

Four Corners and the Navajo Generating Station are located on the Navajo Reservation and are held under easements granted by the federal government as well as leases from the Navajo Nation. APS is the Four Corners operating agent. APS owns a 100% interest in Four Corners Units 1, 2, and 3, and a 15% interest in Four Corners Units 4 and 5. APS owns a 14% interest in Navajo Generating Station Units 1, 2, and 3.

In July 1995, the Navajo Nation enacted the Navajo Nation Air Pollution Prevention and Control Act, the Navajo Nation Safe Drinking Water Act, and the Navajo Nation Pesticide Act (collectively, the Acts). Pursuant to the Acts, the Navajo Nation Environmental Protection Agency is authorized to promulgate regulations covering air quality, drinking water, and pesticide activities, including those that occur at Four Corners and the Navajo Generating Station. By separate letters dated October 12 and October 13, 1995, the Four Corners participants and the Navajo Generating Station participants requested the United States Secretary of the Interior to resolve their dispute with the Navajo Nation regarding whether or not the Acts apply to operations of Four Corners and the Navajo Generating Station. On October 17, 1995, the Four Corners participants and the Navajo Generating Station participants each filed a lawsuit in the District Court of the Navajo Nation, Window Rock District, seeking, among other things, a declaratory judgment that:

- their respective leases and federal easements preclude the application of the Acts to the operations of Four Corners and the Navajo Generating Station; and

- the Navajo Nation and its agencies and courts lack adjudicatory jurisdiction to determine the enforceability of the Acts as applied to Four Corners and the Navajo Generating Station.

On October 18, 1995, the Navajo Nation and the Four Corners and Navajo Generating Station participants agreed to indefinitely stay these proceedings so that the parties may attempt to resolve the dispute without litigation. The Secretary and the Court have stayed these proceedings pursuant to a request by the parties. APS cannot currently predict the outcome of this matter.

In February 1998, the EPA promulgated regulations specifying those provisions of the Clean Air Act for which it is appropriate to treat Indian tribes in the same manner as states. The EPA indicated that it believes that the Clean Air Act generally would supersede pre-existing binding agreements that may limit the scope of tribal authority over reservations. On April 10, 1998, APS

filed a Petition for Review in the United States Court of Appeals for the District of Columbia. Arizona Public Service Company v. United States Environmental Protection Agency, No. 98-1196. On February 19, 1999, the EPA promulgated regulations setting forth the EPA's approach to issuing Federal operating permits to covered stationary sources on Indian reservations. On April 15, 1999, APS filed a Petition for Review in the United States Court of Appeals for the District of Columbia. Arizona Public Service Company v. United States Environmental Protection Agency, No. 99-1146. After the litigation was filed, the EPA indicated it had not determined whether the Clean Air Act would supersede pre-existing binding agreements involving Four Corners and the Navajo Generating Station. On May 5, 2000, the United States Court of Appeals for the District of Columbia upheld the EPA's regulations on treatment of Indian tribes in the same manner as states. However, the Court determined that the impact of this ruling on the pre-existing binding agreements involving Four Corners and the Navajo Generating Station was not ripe for adjudication because the EPA had not made a determination that the Clean Air Act superseded those agreements. On June 29, 2000, at the request of the Court, APS filed a motion to dismiss Four Corners from this petition on the grounds that the impact of the regulations on pre-existing binding agreements was not "ripe" for judicial resolution based on the EPA's issuance of an official notice indicating that it had not yet determined whether the pre-existing binding agreements with Four Corners and Navajo Generating Station were abrogated by the Clean Air Act. The Court ultimately dismissed Four Corners on these grounds.

In April 2000, the Navajo Tribal Council approved operating permit regulations under the Navajo Nation Air Pollution Prevention and Control Act. We believe that the regulations fail to recognize that the Tribe did not intend to assert jurisdiction over Four Corners and the Navajo Generating Station. On July 12, 2000, the Four Corners participants and the Navajo Generating Station participants each filed a petition with the Navajo Supreme Court for review of the operating permit regulations. We cannot currently predict the outcome of this matter.

Water Supply

Assured supplies of water are important for our generating plants. At the present time, APS has adequate water to meet its needs. However, conflicting claims to limited amounts of water in the southwestern United States have resulted in numerous court actions in recent years.

Both groundwater and surface water in areas important to APS' operations have been the subject of inquiries, claims, and legal proceedings which will require a number of years to resolve. APS is one of a number of parties in a proceeding before a state court in New Mexico to adjudicate rights to a stream system from which water for Four Corners is derived. (State of New Mexico, in the relation of S.E. Reynolds, State Engineer vs. United States of America, City of Farmington, Utah International, Inc., et al., San Juan County, New Mexico, District Court No. 75-184). An agreement reached with the Navajo Nation in 1985, however, provides that if Four Corners loses a portion of its rights in the adjudication, the Navajo Nation will provide, for a then-agreed upon cost, sufficient water from its allocation to offset the loss.

A summons served on APS in early 1986 required all water claimants in the Lower Gila River Watershed in Arizona to assert any claims to water on or before January 20, 1987, in an action pending in Maricopa County Superior Court. (In re The General Adjudication of All Rights to Use Water in the Gila River System and Source, Supreme Court Nos. WC-79-0001 through WC 79-0004 (Consolidated) [WC-1, WC-2, WC-3 and WC-4 (Consolidated)], Maricopa County Nos. W-1, W-2, W-3 and W-4 (Consolidated)). Palo Verde is located within the geographic area subject to the summons. APS' rights and the rights of the Palo Verde participants to the use of groundwater and

effluent at Palo Verde are potentially at issue in this action. As project manager of Palo Verde, APS filed claims that dispute the court's jurisdiction over the Palo Verde participants' groundwater rights and their contractual rights to effluent relating to Palo Verde. Alternatively, APS seeks confirmation of such rights. Three of APS' other power plants are also located within the geographic area subject to the summons. APS' claims dispute the court's jurisdiction over its groundwater rights with respect to these plants. Alternatively, APS seeks confirmation of such rights. The Arizona Supreme Court issued a decision confirming that certain groundwater rights may be available to the federal government and Indian tribes. APS and other parties petitioned the U.S. Supreme Court for review of this decision and the petition was denied. In addition, the Arizona Supreme Court issued a decision affirming the lower court's criteria for solving groundwater claims. APS and other parties filed motions for reconsideration on one aspect of that decision. Those motions have been denied by the Arizona Supreme Court. Litigation on both of these issues will continue in the trial court. No trial date concerning APS' water rights claims has been set in this matter.

APS has also filed claims to water in the Little Colorado River Watershed in Arizona in an action pending in the Apache County Superior Court. (In re The General Adjudication of All Rights to Use Water in the Little Colorado River System and Source, Supreme Court No. WC-79-0006 WC-6, Apache County No. 6417). APS' groundwater resource utilized at Cholla is within the geographic area subject to the adjudication and is therefore potentially at issue in the case. APS' claims dispute the court's jurisdiction over its groundwater rights. Alternatively, APS seeks confirmation of such rights. The parties are in the process of settlement negotiations with respect to this matter. No trial date concerning our water rights claims has been set in this matter.

Although the foregoing matters remain subject to further evaluation, APS expects that the described litigation will not have a material adverse impact on its financial position, results of operations or liquidity.

BUSINESS OF PINNACLE WEST ENERGY CORPORATION

Pinnacle West Energy Corporation was incorporated in 1999 under the laws of the State of Arizona and is engaged principally in the business of the development and production of wholesale energy. Pinnacle West Energy is the subsidiary through which we intend to conduct our future unregulated generation operations. Pinnacle West Energy's principal offices are located at 400 North Fifth Street, Station 8987, Phoenix, Arizona 85004 (telephone (602) 250-4145).

Pinnacle West Energy's capital expenditures in 2000 were $193 million. Projected capital expenditures are $659 million in 2001; $129 million in 2002; and $254 million in 2003. The amounts include about $122 million in 2003 for capital improvements to existing generating facilities. At December 31, 2000, Pinnacle West Energy had total assets of $229 million.

See Note 3 of Notes to Consolidated Financial statements for information regarding the transfer of APS' generation assets to Pinnacle West Energy. See "Financial Review – Capital Needs and Resources – Capital Resources and Cash Requirements – Pinnacle West Energy" and Note 12 of Notes to Consolidated Financial Statements for information regarding Pinnacle West Energy's generation expansion plans.

BUSINESS OF APS ENERGY SERVICES COMPANY, INC.

APS Energy Services was incorporated in 1998 under the laws of the State of Arizona and is engaged principally in the business of selling unregulated power and related services. APS Energy Services' principal offices are located at 400 East Van Buren Street, Station 8103, Phoenix, Arizona 85004 (telephone (602) 250-5000).

During the first full two years of operations, APS Energy Services' net losses were about $9 million in 1999 and $13 million in 2000. At December 31, 2000, APS Energy Services had total assets of $23 million.

BUSINESS OF SUNCOR DEVELOPMENT COMPANY

SunCor was incorporated in 1965 under the laws of the State of Arizona and is a developer of residential, commercial, and industrial real estate projects in Arizona, New Mexico, and Utah. The principal executive offices of SunCor are located at 3838 North Central, Suite 1500, Phoenix, Arizona 85012 (telephone 602-285-6800). SunCor and its subsidiaries have approximately 790 full and part-time employees.

SunCor's assets consist primarily of land with improvements, commercial buildings, and other real estate investments. SunCor's largest project is the Palm Valley Master Planned Community, which has approximately 5,000 acres remaining to be developed west of Phoenix at its Palm Valley project in the area of the towns of Goodyear and Litchfield Park, Arizona. SunCor has completed the master plan for development of Palm Valley. There has been significant residential and commercial development at Palm Valley by SunCor and by other developers that have acquired land from SunCor or entered into joint ventures with SunCor. Palm Valley currently includes residential subdivisions with golf courses, hotels, restaurants, commercial and retail stores, medical facilities, elementary and secondary schools, a community college, and a retirement community, known as Pebblecreek.

SunCor projects under development include seven master-planned communities and several commercial projects. The commercial projects and five of the master-planned communities are in Arizona. Other master-planned communities are located near St. George, Utah, and Santa Fe, New Mexico. Several of the master-planned communities and commercial projects are joint ventures with other developers, financial partners, or landowners. SunCor will begin two new projects in 2001:

- Hayden Ferry Lakeside – an 18–acre, mixed-use commercial/residential project located in Tempe, Arizona; and

- StoneRidge – an 1,850-acre, master-planned community with golf course amenities in Prescott Valley, Arizona.

For the past three years, SunCor's operating revenues were about: $158 million in 2000; $130 million in 1999; and $124 million in 1998. For those same periods, SunCor's net income was about: $11 million in 2000; $6 million in 1999; and $45 million in 1998. About $40 million of SunCor's 1998 net income represents income related to the recognition of a deferred tax asset. The deferred tax asset relates to net operating losses and book/tax basis differences. SunCor is expected

to realize these benefits in subsequent periods pursuant to an intercompany tax allocation agreement. On a consolidated basis, there was no impact to consolidated net income.

SunCor's capital needs consist primarily of capital expenditures for land development and home construction for SunCor's home-building subsidiary, Golden Heritage Homes, Inc. On the basis of projects now under development, SunCor expects its capital needs over the next three years to be: $75 million in 2001; $23 million in 2002; and $14 million in 2003.

At December 31, 2000, SunCor had total assets of about $462 million. See Note 6 of Notes to Consolidated Financial Statements in Item 8 for information regarding SunCor's long-term debt. SunCor intends to continue its focus on real estate development in master-planned communities and the development of mixed-use residential, commercial, office, and industrial projects.

BUSINESS OF EL DORADO INVESTMENT COMPANY

El Dorado was incorporated in 1983 under the laws of the State of Arizona and is engaged principally in the business of making equity investments in other companies. El Dorado's short-term goal is to convert its venture capital portfolio to cash as quickly and as advantageously as possible. On a long-term basis, we may use El Dorado, when appropriate, as our subsidiary for new ventures that are strategic to our principal business of generating, distributing, and marketing electricity. El Dorado's offices are located at 400 North Fifth Street, Station 9988, Phoenix, Arizona 85004 (telephone 602-250-3517).

At December 31, 2000, El Dorado had an investment in a venture capital partnership, a 54% interest in a privately held company specializing in nuclear spent fuel technology, limited partnership interests in two professional sports teams, and an investment in a technology company. See Note 1 of Notes to Consolidated Financial Statements in Item 8 for information regarding El Dorado's investments.

For the past three years, El Dorado's net income was about: $2 million in 2000; $11 million in 1999; and $5 million in 1998. At December 31, 2000, El Dorado had total assets of $21 million.

ITEM 2. PROPERTIES

Accredited Capacity

APS' present generating facilities have an accredited capacity as follows:

	Capacity(kW)
Coal:	
Units 1, 2, and 3 at Four Corners	560,000
15% owned Units 4 and 5 at Four Corners	222,000
Units 1, 2, and 3 at Cholla Plant	615,000
14% owned Units 1, 2, and 3 at the Navajo Plant	315,000
	1,712,000
Gas or Oil:	
Two steam units at Ocotillo and two steam units at Saguaro	435,000(1)
Eleven combustion turbine units	493,000
Three combined cycle units	255,000
	1,183,000
Nuclear:	
29.1% owned or leased Units 1, 2, and 3 at Palo Verde	1,086,300
Hydro and Solar	6,000
Total	3,987,300

(1) West Phoenix steam units (108,300 kW) are currently mothballed, but are expected to be back in service by summer 2001.

Reserve Margin

APS' 2000 peak one-hour demand on its electric system was recorded on July 25, 2000 at 5,478,500 kW, compared to the 1999 peak of 4,934,700 kW recorded on August 24. Taking into account additional capacity then available to APS under long-term purchase power contracts as well as APS' own generating capacity, APS' capability of meeting system demand on July 25, 2000, amounted to 4,774,600 kW, for an installed reserve margin of (15.3%). The power actually available to APS from its resources fluctuates from time to time due in part to planned outages and technical problems. The available capacity from sources actually operable at the time of the 2000 peak amounted to 3,501,600 kW, for a margin of (27.5%). Firm purchases, including short-term seasonal purchases, totaling 2,238,000 kW were in place at the time of the peak ensuring the ability to meet the load requirement, with an actual reserve margin of 6.4%.

See "Business of Arizona Public Service Company – Purchased Power Agreements" in Item 1 for information about certain of APS' long-term power agreements.

Plant Sites Leased from Navajo Nation

The Navajo Generating Station and Four Corners are located on land held under easements from the federal government and also under leases from the Navajo Nation. These are long term agreements with options to extend, and we do not believe that the risk with respect to enforcement of these easements and leases is material. The majority of coal contracted for use in these plants and certain associated transmission lines are also located on Indian reservations. See "Generating Fuel and Purchased Power — Coal Supply" in Item 1.

See "Generating Fuel and Purchased Power – Coal Supply" in Item 1 for a discussion of changes in the amount of royalty payments and expiration of tax waivers under the Navajo Generating Station and Four Corners leases.

Palo Verde Nuclear Generating Station

Palo Verde Leases

See Note 10 of Notes to Consolidated Financial Statements in Item 8 for a discussion of three sale and leaseback transactions related to Palo Verde Unit 2.

Regulatory

Operation of each of the three Palo Verde units requires an operating license from the NRC. The NRC issued full power operating licenses for Unit 1 in June 1985, Unit 2 in April 1986, and Unit 3 in November 1987. The full power operating licenses, each valid for a period of approximately 40 years, authorize APS, as operating agent for Palo Verde, to operate the three Palo Verde units at full power.

Nuclear Decommissioning Costs

NRC rules on financial assurance requirements for the decommissioning of nuclear power plants provide that a licensee may use an external sinking fund as the exclusive financial assurance mechanism if the licensee recovers estimated total decommissioning costs through cost of service rates or through a "non-bypassable charge." Other mechanisms are prescribed, including prepayment, if the requirements for exclusive reliance on the external sinking fund mechanism are not met. APS currently relies on the external sinking fund mechanism to meet the NRC financial assurance requirements for its interests in Palo Verde Units 1, 2, and 3. The decommissioning costs of Palo Verde Units 1, 2, and 3 are currently included in ACC jurisdictional rates. ACC retail electric competition rules provide that decommissioning costs would be recovered through a non-bypassable "system benefits" charge, which would allow APS to maintain its external sinking fund mechanism. See Note 13 of Notes to Consolidated Financial Statements in Item 8 for additional information about our nuclear decommissioning costs. See "Financial Review – Business Outlook – Competition and Industry Restructuring" in Item 7 and Note 3 of Notes to Consolidated Financial Statements in Item 8 for additional information about the ACC retail electric competition rules and the legal challenges to these rules.

Palo Verde Liability and Insurance Matters

See "Palo Verde Nuclear Generating Station" in Note 12 of Notes to Consolidated Financial Statements in Item 8 for a discussion of the insurance maintained by the Palo Verde participants, including APS, for Palo Verde.

Other Information Regarding Our Properties

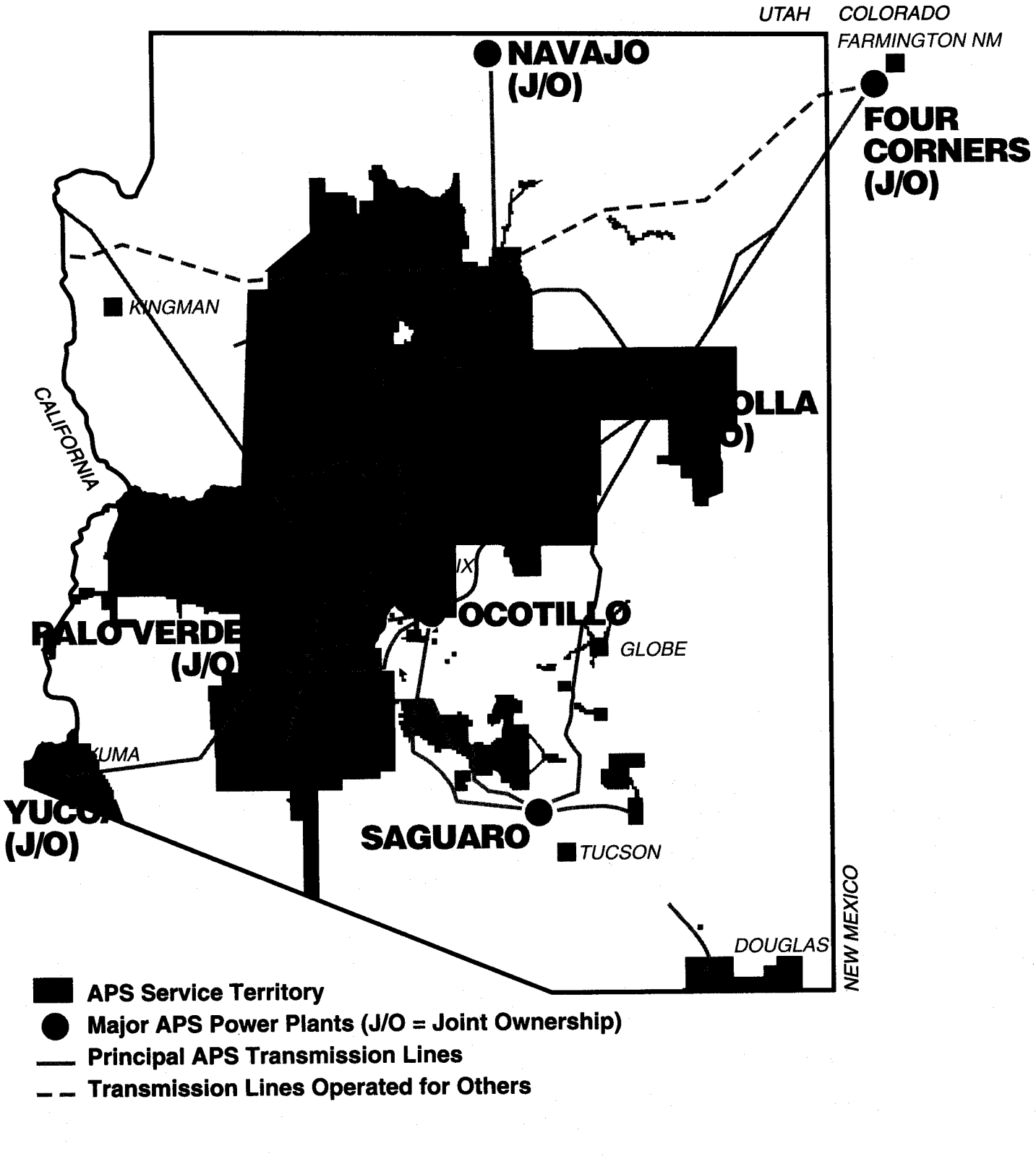
See "Environmental Matters" and "Water Supply" in Item 1 with respect to matters having possible impact on the operation of certain of our power plants.

See "Construction Program" in Item 1 and "Financial Review — Capital Needs and Resources" in Item 7 for a discussion of our construction plans.

See Notes 6, 10, and 11 of Notes to Consolidated Financial Statements in Item 8 with respect to APS' property not held in fee or held subject to any major encumbrance.

Information Regarding Properties of Pinnacle West Energy and SunCor

See "Business of Pinnacle West Energy" and "Business of SunCor Development Company" for information regarding Pinnacle West Energy's and SunCor's properties.


UTAH
COLORADO
FARMINGTON NM
NAVAJO
(J/O)
FOUR
CORNERS
(J/O)
KINGMAN
CALIFORNIA
OLLA
)
OCOTILLO
GLOBE
PALO VERDE
(J/O)
YUMA
YUCCA
(J/O)
SAGUARO
TUCSON
DOUGLAS
NEW MEXICO
APS Service Territory
Major APS Power Plants (J/O = Joint Ownership)
Principal APS Transmission Lines
Transmission Lines Operated for Others

ITEM 3. LEGAL PROCEEDINGS

APS In June 1999, the Navajo Nation served Salt River Project with a lawsuit naming Salt River Project, several Peabody Coal Company entities, Southern California Edison Company and other defendants, and citing various claims in connection with the renegotiations of the coal royalty and lease agreements under which Peabody mines coal for the Navajo Generating Station and the Mohave Generating Station. The Navajo Nation v. Peabody Holding Company, Inc., et al., United States District Court for the District of Columbia, CA-99-0469-EGS. APS is a 14% owner of the Navajo Generating Station, which Salt River Project operates. The suit alleges, among other things, that the defendants obtained a favorable coal royalty rate by improperly influencing the outcome of a federal administrative process under which the royalty rate was to be adjusted. The suit seeks $600 million in damages, treble damages, punitive damages of not less than $1 billion, and the ejection of defendants "from all possessory interests and Navajo Tribal lands" arising out of the [primary coal lease]. Salt River Project has advised APS that it denies all charges and will vigorously defend itself. Because the litigation is in preliminary stages, we cannot currently predict the outcome of this matter.

See "Environmental Matters" and "Water Supply" in Item 1 in regard to pending or threatened litigation and other disputes. See Note 3 of Notes to Consolidated Financial Statements in Item 8 for a discussion of competition and the ACC retail electric competition rules and related litigation. In December 1999, APS filed a lawsuit to protect its legal rights regarding the rules, and in the complaint APS asked the Court for (i) a judgment vacating the retail electric competition rules, (ii) a declaratory judgment that the rules are unlawful because, among other things, they were entered into without proper legal authorization, and (iii) a permanent injunction barring the ACC from enforcing or implementing the rules and from promulgating any other regulations without lawful authority. Arizona Public Service Company v. Arizona Corporation Commission, CV 99-21907. On August 28, 1998, APS filed two lawsuits to protect its legal rights under the stranded cost order and in its complaints APS asked the Court to vacate and set aside the order. Arizona Public Service Company v. Arizona Corporation Commission, CV 98-15728. Arizona Public Service Company v. Arizona Corporation Commission, 1-CA-CC-98-0008.

APS is a party to a power service agreement with Citizens Communications Company under which APS supplies Citizens with power. By letter dated March 7, 2001, Citizens advised APS that it believes APS has overcharged Citizens by over $50 million under the agreement since the summer of 2000. APS believes that its charges to Citizens under the agreement are fully in accordance with the terms of the agreement and APS will vigorously defend any contrary claims raised by Citizens.

ITEM 4. SUBMISSION OF MATTERS TO A VOTE OF SECURITY HOLDERS

Not applicable.

SUPPLEMENTAL ITEM.
EXECUTIVE OFFICERS OF THE REGISTRANT

Our executive officers are as follows:

Name	Age at March 1, 2001	Position(s) at March 1, 2001
William J. Post	50	Chairman of the Board and Chief Executive Officer (1)
Jack E. Davis	54	President and President, APS Energy Delivery and Sales (1)
Robert S. Aiken	44	Vice President, Federal Affairs
John G. Bohon	55	Vice President, Corporate Services & Human Resources
Armando B. Flores	57	Executive Vice President, Corporate Business Services
Edward Z. Fox	47	Vice President, Communications, Environment & Safety
Chris N. Froggatt	43	Vice President & Controller
Barbara M. Gomez	46	Treasurer
James M. Levine	51	Executive Vice President, APS Generation
Nancy C. Loftin	47	Vice President & General Counsel
Michael V. Palmeri	42	Vice President, Finance
Martin L. Shultz	56	Vice President, Government Affairs
William L. Stewart	57	President, APS Generation and President, Pinnacle West Energy
Faye Widenmann	52	Vice President and Secretary

(1) member of the Board of Directors

The executive officers of the Company are elected no less often than annually and may be removed by the Board of Directors at any time. The terms served by the named officers in their current positions and the principal occupations (in addition to those stated in the table) of such officers for the past five years have been as follows:

Mr. Post was elected Chairman of the Board effective February 2001, and Chief Executive Officer effective February 1999. He has served as an officer of the Company since 1995 in the following capacities: from August 1999 to February 2001 as President; from February 1997 to February 1999 as President; and from June 1995 to February 1997 as Executive Vice President. Mr. Post is also Chairman of the Board (since February 2001) and Chief Executive Officer (since February 1997) of APS. He was President of APS from February 1997 until October 1998. In October 1998, he resigned as President and maintained the position of Chief Executive Officer of APS. He was APS' Chief Operating Officer (September 1994–February 1997). Mr. Post is also a director of APS and Blue Cross-Blue Shield of Arizona.

Mr. Davis was elected to his present position effective February 2001. Prior to that time he was Chief Operating Officer and Executive Vice President of Pinnacle West (April 2000-February 2001), Executive Vice President, Commercial Operations of APS (September 1996–October 1998) and Vice President, Energy Delivery and Sales, Generation and Transmission of APS (June 1993–September 1996). Mr. Davis is President of APS (since October 1998) and a director of APS.

Mr. Aiken was elected to his present position in July 1999. Prior to that time he was the Company's Manager, Federal Affairs (November 1986–July 1999).

Mr. Bohon was elected to his present position in July 1999. Prior to that time he was Vice President, Corporate Services and Human Resources of APS (October 1998–July 1999), Vice President, Procurement of APS (April 1997–October 1998) and Director, Corporate Services of APS (December 1989–April 1997).

Mr. Flores was elected to his present position in July 1999. Prior to that time, he was Executive Vice President, Corporate Business Services of APS (October 1998–July 1999), Senior Vice President, Corporate Business Services of APS (September 1996–October 1998) and Vice President, Human Resources of APS (December 1991–September 1996).

Mr. Fox was elected to his present position in July 1999. Prior to that time he was Vice President, Environmental/Health/Safety and New Technology Ventures of APS (October 1995–July 1999).

Mr. Froggatt was elected to his present position in July 1999. Prior to that time he was Controller of APS (July 1997–July 1999) and Director, Accounting Services of APS (December 1992–July 1997).

Ms. Gomez was elected to her present position in August 1999. Prior to that time, she was Manager, Treasury Operations of APS (1997–1999) and Manager, Financial Planning of APS (1994–1997). She was also elected Treasurer of APS in October 1999.

Mr. Levine was elected to his present position in July 1999. Prior to that time he was Senior Vice President, Nuclear Generation of APS (September 1996–July 1999) and Vice President, Nuclear Production of APS (September 1989–September 1996).

Ms. Loftin was elected to her present position in July 1999. She was elected to the positions of Vice President and Chief Legal Counsel of APS in September 1996. Prior to that time, she was Secretary of APS (since April 1987) and Corporate Counsel of APS (since February 1989). She was also elected Vice President and General Counsel of APS in July 1999.

Mr. Palmeri was elected to his present position in August 1999. Prior to that time he was Treasurer of APS and Pinnacle West (July 1997–September 1999) and Assistant Treasurer of Pinnacle West (February 1994–July 1997). He also was elected Vice President, Finance of APS in October 1999.

Mr. Shultz was elected to his current position in July 1999. Prior to that time he held the position of Director of Government Relations for APS (1988–July 1999).

Mr. Stewart was elected to his present position in October 1998. Prior to that time he was Executive Vice President, Generation of APS (September 1996–October 1998) and Executive Vice President, Nuclear of APS (May 1994–September 1996). Mr. Stewart is also President of Pinnacle West Energy.

Ms. Widenmann was elected to her current position in July 1999. Prior to that time, she held the position of Secretary (since 1985) and Vice President of Corporate Relations and Administration (since November 1986). She was also elected Vice President and Secretary of APS in July 1999.

PART II

ITEM 5. MARKET FOR REGISTRANT'S COMMON STOCK AND RELATED SECURITY HOLDER MATTERS

Our common stock is publicly held and is traded on the New York and Pacific Stock Exchanges. At the close of business on March 8, 2001, our common stock was held of record by approximately 39,847 shareholders.

See "Quarterly Stock Prices and Dividends" in Item 6 for a description of the common stock price ranges on the composite tape, as reported in the Wall Street Journal for 2000 and 1999, and the dividends declared during each of the four quarters for 2000 and 1999.

ITEM 6. SELECTED CONSOLIDATED DATA

(dollars in thousands, except per share amounts)

	2000	1999	1998	1997	1996
OPERATING RESULTS					
Operating revenues					
Electric	$ 3,531,810	$ 2,293,184	$ 2,006,398	$ 1,878,553	$ 1,718,272
Real estate	158,365	130,169	124,188	116,473	99,488
Income from continuing operations	$ 302,332	$ 269,772	$ 242,892	$ 235,856	$ 211,059[a]
Discontinued operations	--	38,000[d]	--	--	(9,539)[b]
Extraordinary charge – net of income tax	--	(139,885)[e]	--	--	(20,340)[c]
Net income	$ 302,332	$ 167,887	$ 242,892	$ 235,856	$ 181,180
COMMON STOCK DATA					
Book value per share - year-end	$ 28.09	$ 26.00	$ 25.50	$ 23.90	$ 22.51
Earnings (loss) per average common share outstanding					
Continuing operations – basic	$ 3.57	$ 3.18	$ 2.87	$ 2.76	$ 2.41[a]
Discontinued operations	--	0.45	--	--	(0.11)
Extraordinary charge	--	(1.65)	--	--	(0.23)
Net income – basic	$ 3.57	$ 1.98	$ 2.87	$ 2.76	$ 2.07
Continuing operations – diluted	$ 3.56	$ 3.17	$ 2.85	$ 2.74	$ 2.40[a]
Net income – diluted	$ 3.56	$ 1.97	$ 2.85	$ 2.74	$ 2.06
Dividends declared per share	$ 1.425	$ 1.325	$ 1.225	$ 1.125	$ 1.025
Indicated annual dividend rate – year-end	$ 1.50	$ 1.40	$ 1.30	$ 1.20	$ 1.10
Average common shares outstanding – basic	84,732,544	84,717,135	84,774,218	85,502,909	87,441,515
Average common shares outstanding – diluted	84,935,282	85,008,527	85,345,946	86,022,709	88,021,920
TOTAL ASSETS	$ 7,149,151	$ 6,608,506	$ 6,824,546	$ 6,850,417	$ 6,989,289
LIABILITIES AND EQUITY					
Long-term debt less current maturities	$ 1,955,083	$ 2,206,052	$ 2,048,961	$ 2,244,248	$ 2,372,113
Other liabilities	2,811,354	2,196,721	2,516,993	2,407,572	2,428,180
	4,766,437	4,402,773	4,565,954	4,651,820	4,800,293
Minority interests					
Non-redeemable preferred stock of APS	--	--	85,840	142,051	165,673
Redeemable preferred stock of APS	--	--	9,401	29,110	53,000
Common stock equity	2,382,714	2,205,733	2,163,351	2,027,436	1,970,323
Total liabilities and equity	$ 7,149,151	$ 6,608,506	$ 6,824,546	$ 6,850,417	$ 6,989,289

(a) Includes an after-tax charge of $18.9 million ($0.22 per share) for a voluntary severance program and about $12 million ($0.13 per share) of income tax benefits related to capital loss carryforwards.

(b) Charges, net of tax, associated with the settlement of a legal matter related to MeraBank, A Federal Savings Bank.

(c) Charges associated with the repayment or refinancing of the parent company's high-coupon debt.

(d) Tax benefit stemming from the resolution of income tax matters related to MeraBank, A Federal Savings Bank.

(e) Charges associated with a regulatory disallowance.

(dollars in thousands, except per share amounts)

	2000	1999	1998	1997	1996
ELECTRIC OPERATING REVENUES					
Residential	$ 880,468	$ 805,173	$ 766,378	$ 746,937	$ 721,877
Commercial	771,909	733,038	699,016	687,988	678,130
Industrial	146,088	159,329	172,296	164,696	162,324
Irrigation	6,498	7,374	7,288	8,706	9,448
Other	10,719	11,708	10,644	11,842	13,078
Total retail	1,815,682	1,716,622	1,655,622	1,620,169	1,584,857
Wholesale	1,594,541	506,877	300,698	226,828	98,560
Transmission for others	14,766	11,348	11,058	10,295	10,240
Miscellaneous services	106,821	58,337	39,020	21,261	24,615
Total electric operating revenues	$ 3,531,810	$ 2,293,184	$ 2,006,398	$ 1,878,553	$ 1,718,272
ELECTRIC SALES (MWH)					
Residential	9,780,680	8,774,822	8,310,689	7,970,309	7,541,440
Commercial	10,057,707	9,543,853	8,697,397	8,524,882	8,233,762
Industrial	2,511,292	2,561,349	3,279,430	3,123,283	3,039,357
Irrigation	87,073	99,669	84,640	112,363	121,775
Other	97,772	94,877	90,927	86,090	84,362
Total retail	22,534,524	21,074,570	20,463,083	19,816,927	19,020,696
Wholesale	21,997,357	15,693,834	10,317,391	9,233,573	3,367,234
Total electric sales	44,531,881	36,768,404	30,780,474	29,050,500	22,387,930
ELECTRIC CUSTOMERS – END OF YEAR					
Residential	762,574	735,359	708,215	680,478	654,602
Commercial	90,273	86,707	83,506	81,246	78,178
Industrial	3,286	3,183	3,084	3,192	3,055
Irrigation	371	754	710	764	841
Other	965	932	895	851	828
Total retail	857,469	826,935	796,410	766,531	737,504
Wholesale	67	73	67	50	48
Total electric customers	857,536	827,008	796,477	766,581	737,552

See "Financial Review" on pages 29-45 for a discussion of certain information in the table above.

QUARTERLY STOCK PRICES AND DIVIDENDS
STOCK SYMBOL: PNW

2000	High	Low	Close	Dividends Per Share
1st Quarter	$32.31	$26.25	$28.19	$ 0.350
2nd Quarter	35.88	27.88	33.88	0.350
3rd Quarter	51.31	33.81	50.89	0.350
4th Quarter	52.22	40.89	47.63	0.375

1999	High	Low	Close	Dividends Per Share(a)
1st Quarter	$43.38	$35.94	$36.38	$ 0.325
2nd Quarter	42.94	36.25	40.25	0.650
3rd Quarter	41.31	34.69	36.38	--
4th Quarter	38.13	30.19	30.56	0.350

(a) Dividends for the 3rd quarter of 1999 were declared in June 1999.

ITEM 7. FINANCIAL REVIEW

Introduction

In this section, we explain the results of operations, general financial condition, and outlook for Pinnacle West and our subsidiaries: Arizona Public Service Company (APS), Pinnacle West Energy Corporation (Pinnacle West Energy), APS Energy Services Company, Inc. (APS Energy Services), SunCor Development Company (SunCor), and El Dorado Investment Company (El Dorado), including:

- the changes in our earnings from 1999 to 2000 and from 1998 to 1999;
- the effects of regulatory agreements on our results and outlook;
- our capital needs and resources;
- major factors that affect our financial outlook; and
- our management of market risks.

Overview of Our Business

Pinnacle West owns all of the outstanding common stock of APS. APS is Arizona's largest electric utility and provides retail and wholesale electric service to the entire state with the exception of Tucson and about one-half of the Phoenix area. APS also generates and, directly or through our power marketing division, sells and delivers electricity to wholesale customers in the western United States.

Our other major subsidiaries are:

- Pinnacle West Energy, through which we intend to conduct our unregulated generation operations;
- APS Energy Services, which sells energy and energy-related products and services in competitive retail markets in the western United States;
- SunCor, which is a developer of residential, commercial, and industrial real estate projects in Arizona, New Mexico, and Utah; and
- El Dorado, which is primarily a venture capital and investment firm.

Our Business Strategies

Our business strategies are linked to the strong growth characteristics of Arizona and the western regional market. We are committed to the West and are pursuing the following primary strategies:

- Continuing focus on customer value provided by APS, our regulated "energy delivery" company;

- Expanding our interests in competitively efficient generation assets in the West through Pinnacle West Energy by developing new plants, increasing our ownership share of plants that we already operate and partially own, and buying plants from other utilities;

- Aggressively managing costs, with an emphasis on the reduction of variable costs per generating unit (fuel, operations, and maintenance expenses) and on increased productivity through technological efficiencies; and

- Managing energy activities, including:

    - continuing expansion of wholesale operations;
    - managing commodity price risk; and
    - providing sufficient capacity, energy, and ancillary services to reliably meet obligations to our regulated service customers.

Business Segments

As we discuss below in greater detail, APS' 1999 Settlement Agreement with the Arizona Corporation Commission (ACC) authorizes APS to transfer its competitive generation assets and services to one or more corporate affiliates no later than December 31, 2002. We have internally organized our operations into the following two principal business segments, determined by products, services, and regulatory environment:

- The electricity delivery business segment, which consists of the transmission and distribution of electricity and wholesale activities; and

- The generation business segment, which consists of our generation activities.

See "Business Segments" in Note 18 for more information about our business segments. In general, we have structured our discussion below based on existing legal entities rather than the operating segments defined by the new organizational structure because we continue to analyze these matters internally by legal entity. The "Results of Operations," for example, primarily reflect the results of APS' operations because APS currently owns substantially all of our assets and produces substantially all of our profits.

Throughout this Financial Review, we refer to specific "Notes" in the Notes to Consolidated Financial Statements that begin on page 54. These Notes add further details to the discussion.

Results of Operations

The following is a summary of net income for 2000, 1999, and 1998:

(dollars in millions)	2000	1999	1998
APS	$ 307	$ 267	$ 246
Pinnacle West Energy	(2)	--	--
APS Energy Services	(13)	(9)	--
SunCor	11	6	45
El Dorado	2	11	5
Parent Company	(3)	(5)	(53)
Income from Continuing Operations	302	270	243
Income Tax Benefit from Discontinued Operations	--	38	--
Extraordinary Charge – Net of Income Taxes of $94	--	(140)	--
Net Income	$ 302	$ 168	$ 243

2000 Compared with 1999

Our 2000 consolidated net income was $302 million compared with $168 million in 1999. Our 2000 net income increased $134 million over 1999 primarily because of a $140 million after-tax extraordinary charge that we recorded in 1999. This charge reflected a regulatory disallowance resulting from an ACC-approved Settlement Agreement related to the implementation of retail electric competition. The resulting increase in our 2000 net income was partially offset by a $38 million income tax benefit from discontinued operations that we also recorded in 1999. See "Regulatory Agreements" below and Notes 1 and 3 for additional information about the 1999 Settlement Agreement and the resulting regulatory disallowance. See Note 4 for additional information about the income tax benefit from discontinued operations.

Income from continuing operations increased $32 million, or 12%, over 1999 primarily because of increases in wholesale and retail electric sales and in real estate profits. These positive factors more than offset decreases resulting from the completion of investment tax credit (ITC) amortization in 1999, reductions in retail electricity prices, lower earnings from El Dorado, and miscellaneous factors. See "Regulatory Agreements" below and Note 3 for information on the price reductions. See "Regulatory Agreements" below and Note 4 for additional information about ITC amortization.

In 2000, electric operating revenues increased $1.2 billion primarily because of:

- increased wholesale revenues ($1.1 billion);
- increases in the number of retail electricity customers and the average amount of electricity used by customers ($97 million); and
- weather impacts ($33 million).

As mentioned above, these positive factors were partially offset by the effects of reductions in retail electricity prices ($28 million).

The increase in wholesale revenues resulted primarily from higher prices and increased activity in western United States wholesale power markets. These revenues were accompanied by increases in purchased power and fuel expense of $1.0 billion.

Fuel and purchased power expenses were also higher because of higher retail sales volumes and increased prices.

The increase in real estate profits resulted from increases in sales of land and homes by SunCor.

The increase in operations and maintenance expenses, which primarily related to customer growth, was substantially offset by $20 million of non-recurring items recorded in 1999.

Net other income and expense decreased $11 million primarily because of a decrease in the market value of El Dorado's investment in a technology-related venture capital partnership. See Note 1 for additional information about the valuation of El Dorado's investments.

1999 Compared with 1998

Our 1999 consolidated net income was $168 million compared with $243 million in 1998. Our 1999 net income decreased $75 million from 1998 primarily because of a $140 million after-tax extraordinary charge that we recorded in 1999. This charge reflected a regulatory disallowance resulting from an ACC-approved Settlement Agreement related to the implementation of retail electric competition. The resulting decrease in our 1999 net income was partially offset by a $38 million income tax benefit from discontinued operations that we also recorded in 1999. See "Regulatory Agreements" below and Notes 1 and 3 for additional information about the 1999 Settlement Agreement and the resulting regulatory disallowance. See Note 4 for additional information about the income tax benefit from discontinued operations.

Income from continuing operations increased $27 million, or 11%, over 1998 primarily because of increases in retail electricity revenues and lower financing costs. These positive factors more than offset the effects of retail electricity price reductions and higher utility operations and maintenance expense. See "Regulatory Agreements" below and Note 3 for additional information about the price reductions.

In 1999, electric operating revenues increased $287 million primarily because of:

- increased wholesale revenues ($219 million);
- increases in retail electricity customers and the average amount of electricity used by customers ($81 million); and
- miscellaneous factors ($9 million).

As mentioned above, these positive factors were partially offset by the effects of reductions in retail prices ($22 million).

The increase in wholesale revenues resulted from higher prices and increased activity in western United States wholesale markets. The revenues were accompanied by an increase in purchased power expenses. Although these activities contributed positively to earnings in both periods, the contribution in 1999 was lower than in 1998.

Operations and maintenance expenses increased $27 million primarily because of $20 million of non-recurring items recorded in 1999, including a provision for certain environmental costs. Other increases primarily related to customer growth were partially offset by lower employee benefit costs.

Net other income and expense increased $10 million primarily because of an increase in the market value of El Dorado's investment in a technology-related venture capital partnership. See Note 1 for additional information about the valuation of El Dorado's investments.

Regulatory Agreements

Regulatory agreements approved by the ACC affect the results of APS' operations. The following discussion focuses on three agreements approved by the ACC, each of which included retail electricity price reductions:

- The 1999 Settlement Agreement to implement retail electric competition;
- A 1996 agreement that accelerated the amortization of APS' regulatory assets; and
- A 1994 settlement that accelerated the amortization of APS' deferred ITCs.

1999 Settlement Agreement

As part of the 1999 Settlement Agreement, APS agreed to reduce retail electricity prices for standard, full offer service customers with loads less than three megawatts in a series of annual decreases of 1.5% on July 1, 1999 through July 1, 2003, for a total of 7.5%. The first reduction of approximately $24 million ($14 million after income taxes) included the July 1, 1999 retail price decrease required by the 1996 regulatory agreement (see below). For customers having loads three megawatts or greater, standard offer rates will be reduced in annual increments that total 5% in the years 1999 through 2002.

The 1999 Settlement Agreement also removed, as a regulatory disallowance, $234 million before income taxes ($183 million net present value) from ongoing regulatory cash flows. APS recorded this regulatory disallowance as a net reduction of regulatory assets and reported it as a $140 million after-tax extraordinary charge on the 1999 income statement.

Under the 1996 Regulatory Agreement, APS was recovering substantially all of its regulatory assets through accelerated amortization over an eight-year period that would have ended June 30, 2004. For more details, see Note 1. The regulatory assets to be recovered under the 1999 Settlement Agreement are now being amortized as follows:

(dollars in millions)						
1999	2000	2001	2002	2003	1/1 - 6/30 2004	Total
$164	$158	$145	$115	$86	$18	$686

See Note 3 and "Business Outlook – Electric Competition (Retail)" below for additional information regarding the 1999 Settlement Agreement.

1996 Regulatory Agreement

As part of the 1996 regulatory agreement, APS reduced its retail electricity prices by 3.4% effective July 1, 1996. This reduction decreased annual revenue by about $49 million annually ($29 million after income taxes). APS also agreed to share future cost savings with its customers during the term of this agreement, which resulted in the following additional retail price reductions:

- $18 million annually ($11 million after income taxes), or 1.2%, effective July 1, 1997;
- $17 million annually ($10 million after income taxes), or 1.1%, effective July 1, 1998; and
- $11 million annually ($7 million after income taxes), or 0.7%, effective July 1, 1999 (as noted above, this reduction was included in the July 1, 1999 price reduction under the 1999 Settlement Agreement).

1994 Rate Settlement

As part of a 1994 rate settlement, APS accelerated amortization of substantially all of its ITCs over a five-year period that ended on December 31, 1999. The amortization of ITCs decreased annual consolidated income tax expense by about $24 million. Beginning in 2000, no further benefits were reflected in income tax expense related to the acceleration of the ITCs (see Note 4).

Capital Needs and Resources

Capital Expenditure Requirements

The following table summarizes the actual capital expenditures for the period ended December 31, 2000 and estimated capital expenditures for the next three years:

CAPITAL EXPENDITURES
(dollars in millions)

	(actual)	(estimated)		
	2000	2001	2002	2003
APS				
Delivery	$ 285	$ 337	$ 293	$ 294
Existing Generation (a)	187	118	108	--
	472	455	401	294
Pinnacle West Energy (b)				
Generation Expansion	193	659	129	132
Existing Generation (a)	--	--	--	122
	193	659	129	254
SunCor (c)	50	75	23	14
Other (d)	--	21	9	9
Total	$ 715	$1,210	$ 562	$ 571

(a) Pursuant to the 1999 Settlement Agreement, APS is required to move its generating assets and competitive services no later than December 31, 2002.
(b) Does not include the Southern California Edison (SCE) purchase agreements. See Note 12 and "Capital Resources and Cash Requirements - Pinnacle West Energy" below.
(c) Consists primarily of capital expenditures for land development and retail and office building construction.
(d) Primarily APS Energy Services.

Capital Resources and Cash Requirements

Pinnacle West (Parent Company)

During the past three years, our primary cash needs were for:

- dividends to our shareholders;
- equity infusions into our subsidiaries, including $200 million invested in APS from 1996 through 1999 as part of the 1996 regulatory agreement (see Note 3) and $193 million invested in Pinnacle West Energy for 2000 capital expenditures;
- interest payments; and
- optional and mandatory repayment of principal on our long-term debt.

Over the next three years, we anticipate that our cash needs will fall into these same categories, although we expect our equity infusions into Pinnacle West Energy to continue as it

invests in additional generating facilities (see below) until it begins to finance its own construction needs.

Our primary sources of cash are dividends from our subsidiaries and external financing. For the years 1998 through 2000, total dividends from subsidiaries were $596 million, which included $510 million from APS, $50 million from SunCor, and $36 million from El Dorado.

Our long-term debt at December 31, 2000 was $238 million compared to $106 million at December 31, 1999. We have a $250 million line of credit, under which we had $188 million of borrowings outstanding at December 31, 2000. Our debt repayment requirements for the next three years are approximately: $213 million in 2001, zero in 2002, and $25 million in 2003.

APS

APS' capital requirements consist primarily of capital expenditures and optional and mandatory redemptions of long-term debt. APS pays for its capital requirements with cash from operations and, to the extent necessary, external financing.

During the period from 1998 through 2000, APS paid for substantially all of its capital expenditures with cash from operations. APS expects to do so in 2001 through 2003, as well.

See the table above for actual capital expenditures in 2000 and projected capital expenditures for the next three years. In general, most of APS' projected capital expenditures are for:

- expanding transmission and distribution capabilities to serve growing customer needs;
- upgrading existing utility property; and
- environmental purposes.

During 2000, APS redeemed approximately $357 million of long-term debt, including premiums, with cash from operations and from the issuance of long- and short-term debt. APS' long-term debt redemption requirements for the next three years are approximately: $380 million in 2001; $125 million in 2002; and zero in 2003. APS made optional redemptions of about $13 million of long-term debt in February 2001. Based on market conditions and optional call provisions, APS may make optional redemptions of long-term debt from time to time.

As of December 31, 2000, APS had credit commitments from various banks totaling about $250 million, which were available either to support the issuance of commercial paper or to be used as bank borrowings. At the end of 2000, APS had about $82 million of commercial paper and no long-term bank borrowings outstanding.

APS' long-term debt was $2.1 billion at December 31, 2000 and 1999.

Although provisions in APS' first mortgage bond indenture and ACC financing orders establish maximum amounts of additional first mortgage bonds that APS may issue, APS does not expect any of these provisions to limit its ability to meet its capital requirements.

Pinnacle West Energy

Pinnacle West Energy has announced plans to build up to 2,800 megawatts (MW) of generating capacity from 2001-2006 at an estimated cost of about $1.3 billion.

Site	MW
West Phoenix 4	120
West Phoenix 5	530
Redhawk 1	530
Redhawk 2	530
Redhawk 3	530
Redhawk 4	530
TOTAL	2,770

As discussed in greater detail below, Pinnacle West Energy has also announced plans to purchase Nevada Power Company's (NPC) Harry Allen Power Station and SCE's interest in the Palo Verde Nuclear Generating Station (Palo Verde).

Pinnacle West Energy is also considering additional expansion, which may result in additional expenditures.

Pinnacle West Energy expects to fund its capital requirements through internally generated cash, debt issued directly by Pinnacle West Energy, and capital infusions from the parent company's internally generated cash and external financing.

Pinnacle West Energy is currently planning a 650 MW expansion of the West Phoenix Power Plant and the construction of a natural gas-fired electric generating station of up to four, 530 MW units, near the Palo Verde, called Redhawk. Construction on the 120 MW West Phoenix Unit 4 began in June 2000, with commercial operation of the unit expected in the summer of 2001. Pinnacle West Energy expects construction to begin on the 530 MW West Phoenix Unit 5 in the fall of 2001, with commercial operation beginning in mid-2003. Construction began on the first two units of Redhawk in December 2000, and commercial operation is currently scheduled for the summer of 2002.

Pinnacle West Energy has entered into an agreement with NPC to purchase NPC's 72 MW gas-fired Harry Allen Power Station about 30 miles northeast of Las Vegas, Nevada, for a net purchase price, after adjustments for purchased power commitments, of approximately $65.2 million. The purchase is subject to filing with and/or approval of various regulatory agencies, including the Federal Energy Regulatory Commission (FERC) and the Nevada Public Utility Commission (NPUC). The filing with the NPUC was made in February 2001. NPC will have the right, but not the obligation, to purchase the output from the Harry Allen plant at market rates, subject to a floor and a cap. As demand grows in the region during the next five years, Pinnacle West Energy expects to add a 480 MW gas-fired, combined cycle unit to the site. The Governor of Nevada recently requested that the NPUC reexamine NPC's divestiture of generation assets. The timing and result of any action by the NPUC is not yet known.

On April 27, 2000, Pinnacle West Energy entered into two separate agreements with SCE to purchase SCE's 15.8% ownership interest in Palo Verde and its 48% ownership interest in the Four Corners Power Plant. Consistent with the agreements, on January 5, 2001, Pinnacle West Energy informed SCE that it would not match a competing bid that SCE received for its Four Corners ownership interest. Therefore, Pinnacle West Energy will not purchase SCE's Four Corners interest under the April 2000 agreement unless the Palo Verde transaction closes, the competing Four Corners transaction does not close, and Pinnacle West Energy acquires the Four Corners interest at the original $300 million purchase price as a standby purchaser. SCE did not receive any qualified competing bids for its Palo Verde ownership interest, which Pinnacle West Energy agreed to purchase for $250 million. However, recently-enacted California legislation provides that "no facility for the generation of electricity owned by a public utility may be disposed of prior to January 1, 2006." Unless this California law is amended, Pinnacle West Energy would not be able to acquire SCE's Palo Verde ownership interest pursuant to the original April 2000 agreement.

Other Subsidiaries

During the past three years, SunCor and El Dorado each funded all of their cash requirements with cash from operations and, in the case of SunCor, its own external financings. APS Energy Services funded its cash requirements with cash infusions from the parent company.

SunCor's capital needs consist primarily of capital expenditures for land development and retail and office building construction. See the Capital Expenditures Table above for actual capital expenditures in 2000 and projected capital expenditures for the next three years. SunCor expects to fund its capital requirements from internally generated cash and external financings.

As of December 31, 2000, SunCor had a $120 million line of credit, under which $110 million of borrowings were outstanding. SunCor's debt repayment obligations for the next three years are approximately: zero in 2001; $37 million in 2002; and $74 million in 2003.

El Dorado does not have any capital requirements over the next three years. El Dorado intends to focus on the realization of the value of its existing investments. El Dorado's future investments are expected to be limited to opportunities related to the energy sector.

APS Energy Services' capital expenditures and other cash requirements will be funded from cash invested by the parent company.

Accounting Matters

We adopted a new standard on accounting for derivatives in 2001. As a result, in January 2001 we recognized a $3 million after-tax loss in net income as a cumulative effect of a change in accounting principles, and a $64 million after-tax gain in equity (as a component of other comprehensive income). The gain resulted from unrealized gains on cash flow hedges. There are still several unresolved issues related to the application of certain provisions of this new standard as it relates to the electric utility industry. The ultimate resolution of these issues by the Financial Accounting Standards Board (FASB) could result in a material impact to our financial statements and increased volatility in future net income and comprehensive income. See Note 2 for further information. Also, see Note 2 for a description of a proposed standard on accounting for certain liabilities related to closure or removal of long-lived assets.

We prepare our financial statements in accordance with Statement of Financial Accounting Standards (SFAS) No. 71, "Accounting for the Effects of Certain Types of Regulation." SFAS No. 71 requires a cost-based, rate-regulated enterprise to reflect the impact of regulatory decisions in our financial statements. As a result of the 1999 Settlement Agreement (see "Regulatory Agreements" above and Note 3), we discontinued the application of SFAS No. 71 for our generation operations. As a result, we tested the generation assets for impairment and determined that the generation assets were not impaired. Pursuant to the 1999 Settlement Agreement, we reported a regulatory disallowance ($140 million after income taxes) as an extraordinary charge on the 1999 income statement. See Note 1 for additional information on regulatory accounting and Note 3 for additional information on the 1999 Settlement Agreement.

Business Outlook

This section describes several major factors affecting our financial outlook.

Competition and Industry Restructuring

Electric Competition (Wholesale)

The National Energy Policy Act of 1992 (1992 Energy Act) and the FERC's subsequent rulemaking activities have established the regulatory framework to open the wholesale electricity market to competition. The 1992 Energy Act amended provisions of the Public Utility Holding Company Act of 1935 and the Federal Power Act to remove certain barriers to a competitive wholesale market. The 1992 Energy Act permits utilities to participate in the development of independent electric generating plants for electricity sales to wholesale customers, and also permits the FERC to order transmission access for third parties to transmission facilities owned by another entity. The 1992 Energy Act does not, however, permit the FERC to issue an order requiring transmission access to retail customers. Open-access transmission for wholesale customers as defined by the FERC's final rules provides energy suppliers, including us, with opportunities to sell and deliver electricity at market-based prices.

Electric Competition (Retail)

On September 21, 1999, the ACC voted to approve the rules that provide a framework for the introduction of retail electric competition in Arizona (the Rules). Among other things, the Rules require most utilities, including APS, to transfer all competitive generation assets and services either to an unaffiliated party or to a separate corporate affiliate. The Rules require the transfer to take place by January 1, 2001, absent a waiver. APS received a waiver in the 1999 Settlement Agreement to allow the transfer of its competitive generation assets and services to affiliates no later than December 31, 2002. Accordingly, we plan to complete the move of such assets and services from APS to the parent company or to Pinnacle West Energy by the end of 2002, as required.

Although the Rules allow retail customers to have access to competitive providers of energy and energy services, APS is the "provider of last resort" for standard offer customers under rates that have been approved by the ACC. These rates are fixed until July 1, 2004. The 1999 Settlement Agreement allows APS to seek adjustment of these rates in the event of emergency conditions or circumstances, such as the inability to secure financing on reasonable terms, or material changes in APS' cost of service for ACC-regulated services resulting from federal, tribal, state or local laws, regulatory requirements, judicial decisions, actions or orders. Energy prices in the western wholesale

market vary and, during the course of the last year, have been volatile. At various times prices in the spot wholesale market have significantly exceeded the amount included in APS' current retail rates. APS expects these market conditions to continue in 2001. We believe we have adequately supplemented our current generation portfolio with power purchased through contracts and hedging techniques that limit exposure to the volatile spot wholesale power market. However, in the event of shortfalls due to unforeseen increases in load demand or generation outages, APS may need to purchase additional supplemental power in the wholesale spot market. Unless APS is able to obtain an adjustment of its rates under the 1999 Settlement Agreement, there can be no assurance that APS would be able to fully recover the costs of this power.

As discussed in Note 3 of Notes to Consolidated Financial Statements in Item 8, the 1999 Settlement Agreement authorizes APS to transfer its competitive generation assets and services to one or more corporate affiliates no later than December 31, 2002. APS intends to move its generation assets to Pinnacle West Energy within that timeframe. Following its receipt of these generation assets, Pinnacle West Energy expects to sell its power at wholesale to our power marketing division (Power Marketing). Power Marketing, in turn, is expected to sell power to APS and to non-affiliated power purchasers. APS is expected to meet fifty percent of its energy needs under a power purchase agreement with Power Marketing. As required by the Rules, APS will acquire the remaining fifty percent of its energy needs through a competitive bid process in which Power Marketing may participate. We believe that these arrangements will allow us to manage APS' exposure to the wholesale power market during the period within which APS' rates are fixed, as discussed in the preceding paragraph.

Under the 1999 Settlement Agreement, the Rules are to be interpreted and applied, to the greatest extent possible, in a manner consistent with the 1999 Settlement Agreement. If the two cannot be reconciled, APS must seek, and the other parties to the 1999 Settlement Agreement must support, a waiver of the Rules in favor of the 1999 Settlement Agreement. Several rural electric cooperatives and the Arizona Consumers Council, a private non-profit public interest group (represented by the Arizona Center for Law in the Public Interest, also a private non-profit public interest organization) have filed court challenges to the Rules. Although these actions do not directly challenge the divestiture provisions of the Rules, they do raise fundamental constitutional issues concerning the ability of the ACC to permit the forces of competition to determine retail electric prices.

On November 27, 2000, a Maricopa County, Arizona, Superior Court judge issued a final judgment holding that the Rules are unconstitutional and unlawful in their entirety due to failure to establish a fair value rate base for competitive electric service providers and because certain of the Rules were not submitted to the Arizona Attorney General for certification. The judgment also invalidates all ACC orders authorizing competitive electric service providers, including APS Energy Services, in Arizona. We do not believe the ruling affects the 1999 Settlement Agreement. The 1999 Settlement Agreement was not at issue in the consolidated cases before the judge. Further, the ACC made findings related to the fair value of APS' property in the order approving the 1999 Settlement Agreement. The ACC and other parties aligned with the ACC have appealed the ruling to the Court of Appeals, as a result of which the ruling is automatically stayed pending further judicial review.

On December 13, 1999, two parties filed lawsuits challenging the ACC's approval of the 1999 Settlement Agreement. Each party bringing the lawsuits appealed the ACC's order approving the APS 1999 Settlement Agreement directly to the Arizona Court of Appeals, as provided by Arizona law. In one of the appeals, on December 26, 2000, the Arizona Court of Appeals affirmed the ACC's approval of the 1999 Settlement Agreement. A decision is still pending on the other appeal, which raises a number of different issues.

Neither party challenging the 1999 Settlement Agreement has raised issues regarding the 1999 Settlement Agreement that could not be remedied by the ACC if the Arizona Court of Appeals remands the 1999 Settlement Agreement to the ACC. However, it is impossible to predict with certainty exactly what the ACC would do in the event the order approving the 1999 Settlement Agreement were invalidated, either in whole or in part. Even aside from the pending litigation, the ACC retains continuing jurisdiction over all orders issued by it and can attempt to "rescind, alter or amend" such order under appropriate circumstances and upon notice and hearing.

In May 1998, a law was enacted by the Arizona legislature to facilitate implementation of retail electric competition in the state. Additionally, legislation related to electric competition has been proposed in the United States Congress. See Note 3 for additional information about the Rules, the 1999 Settlement Agreement, the ongoing litigation related to each, and for legislative developments.

As a result of the foregoing matters, as well as energy market developments, particularly in California (see "California Energy Market Issues" below), electric utility restructuring is in a state of flux in the western United States and around the country.

Generation Expansion

See "Capital Needs and Resources -- Capital Resources and Cash Requirements – Pinnacle West Energy" and Note 12 for information regarding our generation expansion plans. The planned additional generation is expected to increase revenues, fuel expenses, operating expenses, and financing costs.

California Energy Market Issues

SCE and PG&E Corp. (PG&E) have publicly disclosed that their liquidity has been materially and adversely affected because of, among other things, their inability to pass on to ratepayers the prices each has paid for energy and ancillary services procured through the California Power Exchange (PX) and California Independent System Operator (ISO).

We are closely monitoring developments in the California energy market and the potential impact of these developments on us and our subsidiaries. We have evaluated, among other things, SCE's role as a Palo Verde and Four Corners participant; APS' transactions with the PX and the ISO; contractual relationships with SCE and PG&E; APS Energy Services' retail transactions involving SCE and PG&E; and power marketing exposures. Based upon the financial transactions to date, we do not believe the foregoing matters will have a material adverse effect on our financial position or liquidity. We cannot predict with certainty, however, the impact that any future resolution, or attempted resolution, of the California energy market situation may have on us or our subsidiaries or the regional energy market in general.

See "Capital Resources and Cash Requirements – Pinnacle West Energy" above for a discussion of Pinnacle West Energy's agreement to purchase SCE's Palo Verde interest.

Factors Affecting Operating Revenues

Electric operating revenues are derived from sales of electricity in regulated retail markets in Arizona, and from competitive retail and wholesale bulk power markets in the western United States.

These revenues are expected to be affected by electricity sales volumes related to customer mix, customer growth and average usage per customer, as well as electricity prices and variations in weather from period to period.

In APS' regulated retail market area, APS will provide electricity services to standard-offer, full-service customers and to energy delivery customers who have chosen another provider for their electricity commodity needs (unbundled customers). Customer growth in APS' service territory averaged 3.8% a year for the three years 1998 through 2000; we currently expect customer growth to average 3.5% to 4% a year for 2001 through 2003. We currently estimate that retail electricity sales in kilowatt-hours will grow 3.5% to 4.5% a year in 2001 through 2003, before the retail effects of weather variations. The customer growth and sales growth referred to in this paragraph apply to energy delivery customers. As industry restructuring evolves in the regulated market area, we cannot predict the number of APS' standard offer customers that will switch to unbundled service.

Wholesale activities will be affected by electricity prices and costs of available fuel and purchased power in the western United States, as well as competitive market conditions and regulatory and legislative changes in various state and federal jurisdictions. These factors have significantly affected our wholesale power activities and their resultant earnings contributions over the last several years. We cannot predict future contributions from wholesale activities.

Competitive sales of energy and energy-related products and services are made by APS Energy Services in western states that have opened to competitive supply. Such activities are currently not material to our consolidated financial results.

Other Factors Affecting Future Financial Results

Fuel and purchased power costs are impacted by our electricity sales volumes, existing contracts for generation fuel and purchased power, our power plant performance, prevailing market prices, and our hedging program for managing such costs.

Operations and maintenance expenses are expected to be affected by sales mix and volumes, inflation, and other factors.

Depreciation and amortization expenses are expected to be affected by net additions to existing utility plant and other property, changes in regulatory asset amortization, and our generation expansion program. See Note 1 for the regulatory asset amortization that is being recorded in 1999 through 2004 pursuant to the 1999 Settlement Agreement. Also, see Note 1 regarding current depreciation rates.

Taxes other than income taxes consist primarily of property taxes, which are affected by tax rates and the value of property in service and under construction. We expect property taxes to increase primarily due to our generation expansion program and our additions to existing facilities.

Interest expense is affected by the amount of debt outstanding and the interest rates on that debt. The primary factors affecting borrowing levels in the next several years are expected to be our generation expansion program and our internally generated cash flow.

The annual earnings contribution from our real estate subsidiary, SunCor, is expected to remain modest over the next several years. SunCor's earnings were $5 million (excluding the effects of a $40 million deferred tax asset transfer) in 1998, $6 million in 1999, and $11 million in 2000.

El Dorado, our investment subsidiary, is affected by market conditions related to its investments. See Note 1 for a discussion of recent events affecting El Dorado's financial results and its outlook. Historical results are not necessarily indicative of future performance for El Dorado. El Dorado's strategies focus on realization of the value of its existing investments. Any future investments are expected to be in the energy business.

Our financial results may be affected by a number of broad factors. See "Forward-Looking Statements" below for further information on such factors, which may cause our actual future results to differ from those we currently seek or anticipate.

We cannot accurately predict the impact of full retail competition on our financial position, cash flows, results of operations, or liquidity. As competition in the electric industry continues to evolve, we will continue to evaluate strategies and alternatives that will position us to compete effectively in a restructured industry.

Market Risks

Our operations include managing market risks related to changes in interest rates, commodity prices, and investments held by the nuclear decommissioning trust fund.

Interest Rate and Equity Risk

Our major financial market risk exposure is changing interest rates. Changing interest rates will affect interest paid on variable-rate debt and interest earned by our nuclear decommissioning trust fund (see Note 13). Our policy is to manage interest rates through the use of a combination of fixed-rate and floating-rate debt. The nuclear decommissioning fund also has risks associated with changing market values of equity investments. Nuclear decommissioning costs are recovered in regulated electricity prices.

The tables below present contractual balances of our long-term debt and commercial paper at the expected maturity dates as well as the fair value of those instruments on December 31, 2000 and December 31, 1999. The interest rates presented in the tables below represent the weighted average interest rates for the years ended December 31, 2000 and December 31, 1999.

Expected Maturity/Principal Repayment
December 31, 2000
(dollars in thousands)

	Short-Term		Variable Long-Term		Fixed Long-Term	
	Interest Rates	Amount	Interest Rates	Amount	Interest Rates	Amount
2001	6.64%	$ 82,775	7.23%	$ 438,203	6.63%	$ 25,266
2002		--	8.62%	36,890	8.13%	125,000
2003		--	8.61%	73,578	6.89%	25,443
2004		--	8.87%	268	6.17%	205,000
2005		--	8.89%	294	7.28%	400,000
Years thereafter		--	4.13%	483,790	7.47%	610,813
Total		$ 82,775		$1,033,023		$1,391,522
Fair value		$ 82,775		$1,033,023		$1,422,014

Expected Maturity/Principal Repayment
December 31, 1999
(dollars in thousands)

	Short-Term		Variable Long-Term		Fixed Long-Term	
	Interest Rates	Amount	Interest Rates	Amount	Interest Rates	Amount
2000	5.33%	$ 38,300	10.25%	$ 87	5.79%	$ 114,711
2001	--	--	7.00%	336,117	6.70%	27,488
2002	--	--	8.47%	64,085	8.13%	125,000
2003	--	--	5.51%	50,118	6.87%	25,000
2004	--	--	10.25%	130	6.17%	205,000
Years thereafter	--	--	3.19%	479,727	7.87%	900,483
Total		$ 38,300		$ 930,264		$1,397,682
Fair value		$ 38,300		$ 930,264		$1,366,968

Commodity Price Risk

Pinnacle West's Energy Risk Management Committee (the ERMC) has established risk management guidelines to monitor and manage commodity price risks. The ERMC is chaired by Pinnacle West's Vice President of Finance and is comprised of senior executives.

We are exposed to the impact of market fluctuations in the price and transportation costs of electricity, natural gas, coal, and emissions allowances. We employ established procedures to manage risks associated with these market fluctuations by utilizing various commodity derivatives, including exchange-traded futures and options and over-the-counter forwards, options, and swaps. As part of our overall risk management program, we enter into derivative transactions to hedge purchases and sales of electricity, fuels, and emissions allowances/credits. In addition, subject to specified risk parameters established by the Board of Directors and monitored by the ERMC, we

engage in trading activities intended to profit from market price movements. In accordance with Emerging Issues Task Force (EITF) 98-10 "Accounting for contracts involved in energy trading and risk management activities", such trading positions are marked to market. These trading activities are part of our wholesale activities and are reflected in the wholesale revenues and expenses.

As of December 31, 2000, a hypothetical adverse price movement of 10% in the market price of our commodity derivative portfolio would have decreased the fair market value of these contracts by approximately $29 million, compared to a $6 million decrease that would have been realized as of December 31, 1999. The increase in this exposure over 1999 is a result of the increased volume of hedged positions and increased prices in this portfolio. This analysis does not include the favorable impact this same hypothetical price move would have had on certain underlying physical exposures being hedged with the commodity derivative portfolio.

We are exposed to losses in the event of non-performance or non-payment by counterparties. We use a risk management process to assess and monitor the financial exposure of counterparties. Despite the fact that the great majority of trading counterparties are rated as investment grade by the credit rating agencies, there is still a possibility that one or more of these companies could default, resulting in a material impact on earnings for a given period.

Forward-Looking Statements

The above discussion contains forward-looking statements based on current expectations and we assume no obligation to update these statements. Because actual results may differ materially from expectations, we caution readers not to place undue reliance on these statements. A number of factors could cause future results to differ materially from historical results, or from results or outcomes currently expected or sought by us. These factors include the ongoing restructuring of the electric industry; the outcome of the regulatory proceedings relating to the restructuring; regional economic and market conditions, including the California energy situation, which could affect customer growth and the cost of power supplies; the cost of debt and equity capital; weather variations affecting local and regional customer energy usage; conservation programs; the successful completion of our generation expansion program; regulatory issues associated with generation expansion, such as permitting and licensing; our ability to compete successfully outside traditional regulated markets (including the wholesale market); technological developments in the electric industry; and the strength of the stock market (particularly the technology sector in which El Dorado is currently invested) and the real estate market in SunCor's market areas, which include Arizona, New Mexico and Utah.

These factors and the other matters discussed above may cause future results to differ materially from historical results, or from results or outcomes we currently expect or seek.

ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

See "Market Risks" in Item 7 for a discussion of quantitative and qualitative disclosures about market risk.

ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

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See Note 14 of Notes to Consolidated Financial Statements for the selected quarterly financial data required to be presented in this Item.

REPORT OF MANAGEMENT

The primary responsibility for the integrity of our financial information rests with management, which has prepared the accompanying financial statements and related information. This information was prepared in accordance with generally accepted accounting principles as appropriate in the circumstances, and based on management's best estimates and judgments. These financial statements have been audited by independent auditors and their report is included on the following page.

Management maintains and relies upon systems of internal control. A limiting factor in all systems of internal control is that the cost of the system should not exceed the benefits to be derived. Management believes that our system provides the appropriate balance between such costs and benefits.

Periodically the internal control system is reviewed by both our internal auditors and our independent auditors to test for compliance. Reports issued by the internal auditors are released to management, and such reports or summaries thereof are transmitted to the Audit Committee of the Board of Directors and the independent auditors on a timely basis. By letter dated February 21, 2001, to the Audit Committee, our independent auditors confirmed that they are independent accountants with respect to us within the meaning of the Securities Act and the requirements of the Independence Standards Board.

The Audit Committee, composed solely of outside directors, meets periodically with the internal auditors and independent auditors (as well as management) to review the work of each. The internal auditors and independent auditors have free access to the Audit Committee, without management present, to discuss the results of their audit work.

Management believes that our systems, policies and procedures provide reasonable assurance that operations are conducted in conformity with the law and with management's commitment to a high standard of business conduct.

William J. Post
Chairman and
Chief Executive Officer

Chris N. Froggatt
Vice President and Controller

INDEPENDENT AUDITORS' REPORT

To the Board of Directors and Stockholders of
Pinnacle West Capital Corporation
Phoenix, Arizona

We have audited the accompanying consolidated balance sheets of Pinnacle West Capital Corporation and subsidiaries as of December 31, 2000 and 1999, and the related consolidated statements of income, retained earnings, and cash flows for each of the three years in the period ended December 31, 2000. Our audits also included the financial statement schedule listed in the Index at Item 14. These financial statements and financial statement schedule are the responsibility of the Corporation's management. Our responsibility is to express an opinion on the financial statements and financial statement schedule based on our audits.

We conducted our audits in accordance with auditing standards generally accepted in the United States of America. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, such consolidated financial statements present fairly, in all material respects, the financial position of Pinnacle West Capital Corporation and subsidiaries at December 31, 2000 and 1999, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2000 in conformity with accounting principles generally accepted in the United States of America. Also, in our opinion, such financial statement schedule, when considered in relation to the basic consolidated financial statements taken as a whole, presents fairly in all material respects the information set forth therein.

Deloitte & Touche LLP

DELOITTE & TOUCHE LLP
Phoenix, Arizona
February 9, 2001

PINNACLE WEST CAPITAL CORPORATION
CONSOLIDATED STATEMENTS OF INCOME
(dollars in thousands, except per share amounts)

	Year Ended December 31,		
	2000	1999	1998
OPERATING REVENUES			
Electric	$ 3,531,810	$ 2,293,184	$ 2,006,398
Real estate	158,365	130,169	124,188
Total	3,690,175	2,423,353	2,130,586
OPERATING EXPENSES			
Fuel and purchased power	1,934,783	796,109	545,297
Operations and maintenance	450,809	446,777	419,433
Real estate operations	134,422	119,516	115,331
Depreciation and amortization (Note 1)	394,410	385,568	379,679
Taxes other than income taxes	99,780	96,606	103,718
Total	3,014,204	1,844,576	1,563,458
OPERATING INCOME	675,971	578,777	567,128
OTHER INCOME (EXPENSE)			
Preferred stock dividend requirements of APS	--	(1,016)	(9,703)
Net other income and expense	(186)	10,793	609
Total	(186)	9,777	(9,094)
INCOME BEFORE INTEREST AND INCOME TAXES	675,785	588,554	558,034
INTEREST EXPENSE			
Interest charges	171,239	162,381	169,145
Capitalized interest	(21,638)	(11,664)	(18,596)
Total	149,601	150,717	150,549
INCOME FROM CONTINUING OPERATIONS BEFORE INCOME TAXES	526,184	437,837	407,485
INCOME TAXES (NOTE 4)	223,852	168,065	164,593
INCOME FROM CONTINUING OPERATIONS	302,332	269,772	242,892
Income tax benefit from discontinued operations	--	38,000	--
Extraordinary charge - net of income taxes of $94,115	--	(139,885)	--
NET INCOME	$ 302,332	$ 167,887	$ 242,892
AVERAGE COMMON SHARES OUTSTANDING – BASIC	84,733	84,717	84,774
AVERAGE COMMON SHARES OUTSTANDING – DILUTED	84,935	85,009	85,346
EARNINGS PER AVERAGE COMMON SHARE OUTSTANDING (NOTE 16)			
Continuing operations – basic	$ 3.57	$ 3.18	$ 2.87
Net income – basic	3.57	1.98	2.87
Continuing operations – diluted	3.56	3.17	2.85
Net income – diluted	3.56	1.97	2.85
DIVIDENDS DECLARED PER SHARE	$ 1.425	$ 1.325	$ 1.225

See Notes to Consolidated Financial Statements.

PINNACLE WEST CAPITAL CORPORATION
CONSOLIDATED BALANCE SHEETS
(dollars in thousands)

	December 31,	
	2000	1999
ASSETS		
CURRENT ASSETS		
Cash and cash equivalents	$ 10,363	$ 20,705
Customer and other receivables – net	513,822	244,599
Accrued utility revenues	74,566	72,919
Materials and supplies (at average cost)	71,966	69,977
Fossil fuel (at average cost)	19,405	21,869
Deferred income taxes (Note 4)	5,793	8,163
Other current assets	97,998	60,562
Total current assets	793,913	498,794
INVESTMENTS AND OTHER ASSETS		
Real estate investments – net (Note 6)	371,323	344,293
Other assets (Note 13)	318,249	267,458
Total investments and other assets	689,572	611,751
UTILITY PLANT (NOTES 6, 10 AND 11)		
Electric plant in service and held for future use	7,809,566	7,546,314
Less accumulated depreciation and amortization	3,188,302	3,026,194
Total	4,621,264	4,520,120
Construction work in progress	464,540	209,281
Nuclear fuel, net of amortization of $61,256 and $66,357	47,389	49,114
Net utility plant	5,133,193	4,778,515
DEFERRED DEBITS		
Regulatory assets (Notes 3 and 4)	469,867	613,729
Other deferred debits	62,606	105,717
Total deferred debits	532,473	719,446
TOTAL ASSETS	$7,149,151	$6,608,506

See Notes to Consolidated Financial Statements.

PINNACLE WEST CAPITAL CORPORATION
CONSOLIDATED BALANCE SHEETS
(dollars in thousands)

	December 31,	
	2000	1999
LIABILITIES AND EQUITY		
CURRENT LIABILITIES		
Accounts payable	$ 375,805	$ 186,524
Accrued taxes	89,246	70,510
Accrued interest	42,954	33,253
Short-term borrowings (Note 5)	82,775	38,300
Current maturities of long-term debt (Note 6)	463,469	114,798
Customer deposits	26,189	26,098
Other current liabilities	110,860	26,007
Total current liabilities	1,191,298	495,490
LONG-TERM DEBT LESS CURRENT MATURITIES (NOTE 6)	1,955,083	2,206,052
DEFERRED CREDITS AND OTHER		
Deferred income taxes (Note 4)	1,143,040	1,183,855
Unamortized gain - (Note 10)	68,636	73,212
Other	408,380	444,164
Total deferred credits and other	1,620,056	1,701,231
COMMITMENTS AND CONTINGENCIES (NOTES 3, 12 AND 13)		
COMMON STOCK EQUITY (NOTE 8)		
Common stock, no par value; authorized 150,000,000 shares; issued and outstanding 84,824,947 at end of 2000 and 1999	1,532,831	1,537,449
Retained earnings	849,883	668,284
Total common stock equity	2,382,714	2,205,733
TOTAL LIABILITIES AND EQUITY	$7,149,151	$6,608,506

See Notes to Consolidated Financial Statements.

PINNACLE WEST CAPITAL CORPORATION
CONSOLIDATED STATEMENTS OF CASH FLOWS
(dollars in thousands)

	Year Ended December 31,		
	2000	1999	1998
CASH FLOWS FROM OPERATING ACTIVITIES			
Income from continuing operations	$ 302,332	$ 269,772	$ 242,892
Items not requiring cash			
Depreciation and amortization	394,410	385,568	379,679
Nuclear fuel amortization	30,083	31,371	32,856
Deferred income taxes – net	(8,973)	(17,413)	41,262
Deferred investment tax credit	740	(23,514)	(23,516)
Other – net	478	(12,476)	1,190
Changes in current assets and liabilities			
Customer and other receivables – net	(269,223)	(10,723)	(50,369)
Accrued utility revenues	(1,647)	(5,179)	(9,181)
Materials, supplies and fossil fuel	475	(8,794)	(2,797)
Other current assets	(37,436)	(12,968)	(6,186)
Accounts payable	193,502	28,193	34,386
Accrued taxes	18,736	12,591	(22,090)
Accrued interest	9,701	1,387	(1,108)
Other current liabilities	89,714	15,047	(5,235)
(Increase) Decrease in land held	(25,937)	(12,542)	33,405
Other – net	2,605	(4,720)	(39,350)
Net Cash Flow Provided By Operating Activities	699,560	635,600	605,838
CASH FLOWS FROM INVESTING ACTIVITIES			
Capital expenditures	(658,608)	(343,448)	(319,142)
Capitalized interest	(21,638)	(11,664)	(18,596)
Other – net	(41,761)	(16,143)	(2,144)
Net Cash Flow Used For Investing Activities	(722,007)	(371,255)	(339,882)
CASH FLOWS FROM FINANCING ACTIVITIES			
Issuance of long-term debt	651,000	607,791	148,229
Short-term borrowings – net	44,475	(140,530)	48,080
Dividends paid on common stock	(120,733)	(112,311)	(103,849)
Repayment of long-term debt	(558,019)	(510,693)	(286,314)
Redemption of preferred stock	--	(96,499)	(75,517)
Other – net	(4,618)	(11,936)	(3,531)
Net Cash Flow Provided by (Used for) Financing Activities	12,105	(264,178)	(272,902)
NET CASH FLOW	(10,342)	167	(6,946)
CASH AND CASH EQUIVALENTS AT BEGINNING OF YEAR	20,705	20,538	27,484
CASH AND CASH EQUIVALENTS AT END OF YEAR	$ 10,363	$ 20,705	$ 20,538

See Notes to Consolidated Financial Statements.

PINNACLE WEST CAPITAL CORPORATION
CONSOLIDATED STATEMENTS OF RETAINED EARNINGS
(dollars in thousands)

	Year Ended December 31,		
	2000	1999	1998
Retained earnings at beginning of year	$ 668,284	$ 612,708	$ 473,665
Net income	302,332	167,887	242,892
Common stock dividends	(120,733)	(112,311)	(103,849)
Retained earnings at end of year	$ 849,883	$ 668,284	$ 612,708

See Notes to Consolidated Financial Statements.

1. Summary of Significant Accounting Policies

Consolidation and Nature of Operations

The consolidated financial statements include the accounts of Pinnacle West and our subsidiaries: APS, Pinnacle West Energy, APS Energy Services, SunCor, and El Dorado. Significant intercompany accounts and transactions between the consolidated companies have been eliminated.

APS, our major subsidiary and Arizona's largest electric utility, provides retail and wholesale electric service to the entire state with the exception of Tucson and about one-half of the Phoenix area. APS also generates and, directly or through our power marketing division, sells and delivers electricity to wholesale customers in the western United States. Pinnacle West Energy, which was formed in 1999, is the subsidiary through which we intend to conduct our unregulated generation operations. APS Energy Services was formed in 1998 and sells energy and energy-related products and services in competitive retail markets in the western United States. SunCor is a developer of residential, commercial, and industrial real estate projects in Arizona, New Mexico, and Utah. El Dorado is primarily a venture capital and investment firm.

Accounting Records

Our accounting records are maintained in accordance with accounting principles generally accepted in the United States of America (GAAP). The preparation of financial statements in accordance with GAAP requires the use of estimates by management. Actual results could differ from those estimates.

Regulatory Accounting

APS is regulated by the ACC and the FERC. The accompanying financial statements reflect the rate-making policies of these commissions. For regulated operations, we prepare our financial statements in accordance with SFAS No. 71, "Accounting for the Effects of Certain Types of Regulation." SFAS No. 71 requires a cost-based, rate-regulated enterprise to reflect the impact of regulatory decisions in our financial statements.

During 1997, the EITF of the FASB issued EITF 97-4. EITF 97-4 requires that SFAS No. 71 be discontinued no later than when legislation is passed or a rate order is issued that contains sufficient detail to determine its effect on the portion of the business being deregulated, which could result in write-downs or write-offs of physical and/or regulatory assets. Additionally, the EITF determined that regulatory assets should not be written off if they are to be recovered from a portion of the entity which continues to apply SFAS No. 71.

The 1999 Settlement Agreement was approved by the ACC in September 1999 (see Note 3 for a discussion of the agreement). Consequently, we have discontinued the application of SFAS No. 71 for our generation operations. As a result, we tested the generation assets for impairment and determined that the generation assets were not impaired. Pursuant to the 1999 Settlement Agreement, a regulatory disallowance removed $234 million pre-tax ($183 million net present value) from ongoing regulatory cash flows and was recorded as a net reduction of regulatory assets. This reduction ($140 million after income taxes) was reported as an extraordinary charge on the income statement during the third quarter of 1999. Prior to the 1999 Settlement Agreement, under the 1996

regulatory agreement (see Note 3), the ACC accelerated the amortization of substantially all of our regulatory assets to an eight-year period that would have ended June 30, 2004.

The regulatory assets to be recovered under the 1999 Settlement Agreement are now being amortized as follows:

(dollars in millions)

1999	2000	2001	2002	2003	1/1 - 6/30 2004	Total
$164	$158	$145	$115	$86	$18	$686

The majority of our remaining regulatory assets relate to deferred income taxes (see Note 4) and rate synchronization cost deferrals (see "Rate Synchronization Cost Deferrals" in this Note).

The balance sheets include the amounts listed below for generation assets not subject to SFAS No. 71 (for additional generation information see Note 18):

(dollars in thousands)

	December 31, 2000	December 31, 1999
Electric plant in service and held for future use	$ 3,856,600	$ 3,817,919
Accumulated depreciation and amortization	(1,693,079)	(1,664,782)
Construction work in progress	304,992	87,819
Nuclear fuel, net of amortization	47,389	49,114

Utility Plant and Depreciation

Utility plant is the term we use to describe the business property and equipment that supports electric service, consisting primarily of generation, transmission, and distribution facilities. We report utility plant at its original cost, which includes:

- material and labor;
- contractor costs;
- construction overhead costs (where applicable); and
- capitalized interest or an allowance for funds used during construction.

We charge retired utility plant, plus removal costs less salvage realized, to accumulated depreciation. See Note 2 for information on a proposed accounting standard that impacts accounting for removal costs.

We record depreciation on utility property on a straight-line basis. For the years 1998 through 2000 the rates, as prescribed by our regulators, ranged from a low of 3.33% to a high of 20%. The weighted-average rate was 3.40% for 2000, 3.34% for 1999, and 3.32% for 1998. We depreciate non-utility property and equipment over the estimated useful lives of the related assets, ranging from 3 to 30 years.

El Dorado Investments

Net other income consists primarily of El Dorado's share in the earnings of a venture capital partnership. The partnership adjusts the value of its investments at the end of each fiscal quarter. The value of El Dorado's investment in the partnership is determined by various factors beyond our control, including equity market conditions. Most of the partnership's investments are in technology-related companies whose share prices are highly volatile.

Prior to June 2000, we recorded our share of the earnings from the partnership, as the partnership adjusted the value of its investment, on a one-quarter lag. This procedure was followed due to time constraints in obtaining and analyzing such results for inclusion in our consolidated financial statements on a current basis. In the second quarter of 2000, we requested a distribution of our share of the investments held by the partnership, and we adjusted our investment to reflect the current market value.

An amendment to the partnership agreement resulted in El Dorado receiving a distribution, subject to certain sale restrictions, of securities representing substantially all of El Dorado's investment in the partnership. We began accounting for the securities as available for sale with changes in fair value recorded in other comprehensive income. Gains and losses from the ultimate sale of such securities will be reflected in our net earnings.

The book value of El Dorado's investment in the partnership was approximately $7 million at December 31, 2000 and $21 million at December 31, 1999.

Capitalized Interest

Capitalized interest represents the cost of debt funds used to finance construction of utility plants. Plant construction costs, including capitalized interest, are expensed through depreciation when completed projects are placed into commercial operation. Capitalized interest does not represent current cash earnings. The rate used to calculate capitalized interest was a composite rate of 6.62% for 2000, 6.65% for 1999, and 6.88% for 1998.

Revenues

We record electric operating revenues on the accrual basis, which includes estimated amounts for service rendered but unbilled at the end of each accounting period.

Rate Synchronization Cost Deferrals

As authorized by the ACC, operating costs (excluding fuel) and financing costs of Palo Verde Units 2 and 3 were deferred from the commercial operation dates (September 1986 for Unit 2 and January 1988 for Unit 3) until the date the units were included in a rate order (April 1988 for Unit 2 and December 1991 for Unit 3). In accordance with the 1999 Settlement Agreement, we are continuing to accelerate the amortization of the deferrals over an eight-year period that will end June 30, 2004. Amortization of the deferrals is included in depreciation and amortization expense on the Statements of Income.

Nuclear Fuel

APS charges nuclear fuel to fuel expense by using the unit-of-production method. The unit-of-production method is an amortization method that is based on actual physical usage. APS divides the cost of the fuel by the estimated number of thermal units that it expects to produce with that fuel. APS then multiplies that rate by the number of thermal units that it produces within the current period. This calculation determines the current period nuclear fuel expense.

APS also charges nuclear fuel expense for the permanent disposal of spent nuclear fuel. The United States Department of Energy (DOE) is responsible for the permanent disposal of spent nuclear fuel, and it charges APS $0.001 per kWh of nuclear generation. See Note 12 for information about spent nuclear fuel disposal and Note 13 for information on nuclear decommissioning costs.

Income Taxes

We file our federal income tax return on a consolidated basis and we file our state income tax returns on a consolidated or unitary basis. In accordance with our intercompany tax sharing agreement, federal and state income taxes are allocated to each subsidiary as though each subsidiary filed a separate income tax return. Any difference between the aforementioned allocations and the consolidated (and unitary) income tax liability is attributed to the parent company.

Reacquired Debt Costs

For debt related to the regulated portion of APS' business, APS amortizes those gains and losses incurred upon early retirement over the remaining life of the debt. In accordance with the 1999 Settlement Agreement, APS is continuing to accelerate reacquired debt costs over an eight-year period that will end June 30, 2004. The accelerated portion of the regulatory asset amortization is included in depreciation and amortization expense in the Statements of Income.

Derivative Instruments

We are exposed to the impact of market fluctuations in the price and transportation costs of electricity, natural gas, coal, and emissions allowances. We employ established procedures to manage risks associated with these market fluctuations by utilizing various commodity derivatives, including exchange-traded futures and options and over-the-counter forwards, options, and swaps. As part of our overall risk management program, we enter into derivative transactions to hedge purchases and sales of electricity, fuels, and emissions allowances/credits. The changes in market value of such contracts have a high correlation to price changes in the hedged commodity. In addition, subject to specified risk parameters established by the Board of Directors and monitored by the ERMC, we engage in trading activities intended to profit from market price movements.

Gains and losses related to derivatives that qualify as hedges of expected transactions are recognized in revenue or fuel and purchased power expense as an offset to the related item being hedged when the underlying hedged physical transaction closes (deferral method).

Net gains and losses on derivatives utilized for trading are recognized in wholesale revenues on a current basis (the mark to market method). Trading positions are measured at fair value as of the balance sheet date. The net gain was $9 million for 2000 and $1 million for 1999.

Statements of Cash Flows

We consider temporary cash investments and marketable securities, with original maturities of less than 90 days, to be cash equivalents for purposes of reporting cash flows. During 2000, 1999, and 1998, we paid interest, net of amounts capitalized, income taxes, and dividends on preferred stock of APS as follows:

(dollars in millions)

	Years Ended December 31,		
	2000	1999	1998
Interest paid	$132	$141	$144
Income taxes paid	219	200	165
Dividends paid on preferred stock of APS	--	1	10

2. Accounting Matters

Effective January 1, 2001, we adopted SFAS No. 133, "Accounting for Derivative Instruments and Hedging Activities." SFAS No. 133 requires that entities recognize all derivatives as either assets or liabilities on the balance sheet and measure those instruments at fair value. Changes in the fair value of derivative financial instruments are either recognized periodically in income or shareholder's equity (as a component of other comprehensive income), depending on whether or not the derivative meets specific hedge accounting criteria. Hedge effectiveness is measured based on the relative changes in fair value between the derivative contract and the hedged item over time. Any change in the fair value resulting from ineffectiveness, as defined by SFAS No. 133, is recognized immediately in net income. This new standard may result in additional volatility in our net income and comprehensive income.

As a result of adopting SFAS No. 133, we recognized $118 million of derivative assets and $16 million of derivative liabilities in our balance sheet as of January 1, 2001. We recorded a $3 million after-tax loss in net income as a cumulative effect of a change in accounting principles and a $64 million after-tax gain in equity (as a component of other comprehensive income). The gain resulted from unrealized gains on cash flow hedges.

In December 2000, the FASB's Derivatives Implementation Group (DIG) discussed whether contracts in the electric industry that have some of the characteristics of purchased and written options should qualify for the "normal purchases and sales" scope exception. The DIG did not reach a conclusion on this issue. We account for electricity contracts with characteristics of options as normal purchases and sales if it is probable that the contract will not be settled in cash and will result in the physical delivery of electricity. The DIG also discussed but did not determine whether electricity contracts subject to "bookout" should qualify for the normal exception. A bookout occurs when one party appears more than once in a contract path for the sale and purchase of energy. In that instance, the counterparties may agree that they will not schedule or deliver physical energy that originates and ends with the same counterparty, but rather will settle in cash the amounts due to or from each counterparty. We account for our non-trading electricity transactions that bookout as gross settlement with physical delivery (and eligible for the normal scope exception) if title transfers, gross cash payment is made, and the transaction retains both performance and credit risk. Trading contracts are measured at fair value (mark to market) as discussed in Note 1.

Our accounting is reflective of the non-storability of our product and the lack of predictability of the demand for electricity at any point in time. If the FASB or DIG ultimately provides us with contrary guidance, we may be required to mark our non-trading electricity contracts to their fair market values each reporting period, which could have a material impact on our financial statements and add significant net income and comprehensive income volatility that would not be reflective of the nature of our business. If these agreements are required to be treated as derivative instruments, a cumulative effect of a change in accounting principles would be applied in the quarter following final resolution of the issues.

In 1999 we adopted EITF 98-10, "Accounting for Contracts Involved in Energy Trading and Risk Management Activities." EITF 98-10 requires energy trading contracts to be measured at fair value as of the balance sheet date with the gains and losses included in earnings and separately disclosed in the financial statements or footnotes. The effects of adopting EITF 98-10 were not material to our 1999 financial statements.

In February 1996, the FASB issued an exposure draft, "Accounting for Certain Liabilities Related to Closure or Removal of Long-Lived Assets." This proposed standard would require the estimated present value of the cost of decommissioning and certain other removal costs to be recorded as a liability, along with an offsetting plant asset when a decommissioning or other removal obligation is incurred. The FASB issued a revised exposure draft in February 2000 and we are evaluating the impacts.

3. Regulatory Matters

Electric Industry Restructuring

State

1999 Settlement Agreement. On May 14, 1999, APS entered into a comprehensive Settlement Agreement with various parties, including representatives of major consumer groups, related to the implementation of retail electric competition. On September 23, 1999, the ACC voted to approve the 1999 Settlement Agreement, with some modifications. On December 13, 1999, two parties filed lawsuits challenging the ACC's approval of the 1999 Settlement Agreement. Each party bringing the lawsuits appealed the ACC's order approving the APS 1999 Settlement Agreement directly to the Arizona Court of Appeals, as provided by Arizona law. In one of the appeals, on December 26, 2000, the Arizona Court of Appeals affirmed the ACC's approval of the 1999 Settlement Agreement. A decision is still pending on the other appeal, which raises a number of different issues.

The following are the major provisions of the 1999 Settlement Agreement, as approved:

- APS has reduced, and will reduce, rates for standard offer service for customers with loads less than three MW in a series of annual retail electric price reductions of 1.5% beginning July 1, 1999 through July 1, 2003, for a total of 7.5%. The first reduction of approximately $24 million ($14 million after income taxes) included the July 1, 1999 retail price decrease of approximately $11 million ($7 million after income taxes) related to the 1996 regulatory agreement. See "1996 Regulatory Agreement" below. Based on the price reduction authorized in the 1999 Settlement Agreement, there was a retail price decrease of approximately $28 million ($17 million after taxes), or 1.5%, effective July 1, 2000. For

customers having loads three MW or greater, standard offer rates will be reduced in varying annual increments that total 5% in the years 1999 through 2002.

- Unbundled rates being charged by APS for competitive direct access service (for example, distribution services) became effective upon approval of the 1999 Settlement Agreement, retroactive to July 1, 1999, and also became subject to annual reductions beginning January 1, 2000, that vary by rate class, through January 1, 2004.

- There will be a moratorium on retail price changes for standard offer and unbundled competitive direct access services until July 1, 2004, except for the price reductions described above and certain other limited circumstances. Neither the ACC nor APS will be prevented from seeking or authorizing rate changes prior to July 1, 2004 in the event of conditions or circumstances that constitute an emergency, such as an inability to finance on reasonable terms, or material changes in APS' cost of service for ACC-regulated services resulting from federal, tribal, state or local laws, regulatory requirements, judicial decisions, actions or orders.

- APS will be permitted to defer for later recovery prudent and reasonable costs of complying with the ACC electric competition rules, system benefits costs in excess of the levels included in current rates, and costs associated with the "provider of last resort" and standard offer obligations for service after July 1, 2004. These costs are to be recovered through an adjustment clause or clauses commencing on July 1, 2004.

- APS' distribution system opened for retail access effective September 24, 1999. Customers were eligible for retail access in accordance with the phase-in adopted by the ACC under the electric competition rules (see "Retail Electric Competition Rules" below), including an additional 140 MW being made available to eligible non-residential customers. APS opened its distribution system to retail access for all customers on January 1, 2001.

- Prior to the 1999 Settlement Agreement, APS was recovering substantially all of its regulatory assets through July 1, 2004, pursuant to the 1996 regulatory agreement. In addition, the 1999 Settlement Agreement states that APS has demonstrated that its allowable stranded costs, after mitigation and exclusive of regulatory assets, are at least $533 million net present value. APS will not be allowed to recover $183 million net present value of the above amounts. The 1999 Settlement Agreement provides that APS will have the opportunity to recover $350 million net present value through a competitive transition charge (CTC) that will remain in effect through December 31, 2004, at which time it will terminate. Any over/under-recovery due to sales volume variances will be credited/debited against the costs subject to recovery under the adjustment clause described above.

- APS will form a separate corporate affiliate or affiliates and transfer to such affiliate(s) its generating assets and competitive services at book value as of the date of transfer, which transfer shall take place no later than December 31, 2002. Accordingly, APS plans to complete the move of such assets and services from APS to the parent company or to Pinnacle West Energy by the end of 2002, as required. APS will be allowed to defer and later collect, beginning July 1, 2004, sixty-seven percent of its costs to accomplish the required transfer of generation assets to an affiliate.

- When the 1999 Settlement Agreement approved by the ACC is no longer subject to judicial review, APS will move to dismiss all of its litigation pending against the ACC as of the date APS entered into the 1999 Settlement Agreement. To protect its rights, APS has several lawsuits pending on ACC orders relating to stranded cost recovery and the adoption and amendment of the ACC's electric competition rules, which would be voluntarily dismissed at the appropriate time under this provision.

As discussed in Note 1 above, we have discontinued the application of SFAS No. 71 for our generation operations.

Retail Electric Competition Rules. On September 21, 1999, the ACC voted to approve the rules that provide a framework for the introduction of retail electric competition in Arizona. Under the 1999 Settlement Agreement, the Rules are to be interpreted and applied, to the greatest extent possible, in a manner consistent with the 1999 Settlement Agreement. If the two cannot be reconciled, APS must seek, and the other parties to the 1999 Settlement Agreement must support, a waiver of the Rules in favor of the 1999 Settlement Agreement. On December 8, 1999, APS filed a lawsuit to protect its legal rights regarding the Rules. This lawsuit is pending, along with several other lawsuits on ACC orders relating to stranded cost recovery, the adoption or amendment of the Rules, and the certification of competitive electric service providers.

On November 27, 2000, a Maricopa County, Arizona, Superior Court judge issued a final judgment holding that the Rules are unconstitutional and unlawful in their entirety due to failure to establish a fair value rate base for competitive electric service providers and because certain of the Rules were not submitted to the Arizona Attorney General for certification. The judgment also invalidates all ACC orders authorizing competitive electric service providers, including APS Energy Services, in Arizona. We do not believe the ruling affects the 1999 Settlement Agreement. The 1999 Settlement Agreement was not at issue in the consolidated cases before the judge. Further, the ACC made findings related to the fair value of APS' property in the order approving the 1999 Settlement Agreement. The ACC and other parties aligned with the ACC have appealed the ruling to the Court of Appeals, as a result of which the ruling is automatically stayed pending further judicial review.

The Rules approved by the ACC include the following major provisions:

- They apply to virtually all Arizona electric utilities regulated by the ACC, including APS.
- Effective January 1, 2001, retail access was available to all APS retail customers.
- Electric service providers that get Certificates of Convenience and Necessity from the ACC can supply only competitive services, including electric generation, but not electric transmission and distribution.
- Affected utilities must file ACC tariffs that unbundle rates for non-competitive services.
- The ACC shall allow a reasonable opportunity for recovery of unmitigated stranded costs.
- Absent an ACC waiver, prior to January 1, 2001, each affected utility (except certain electric cooperatives) must transfer all competitive generation assets and services either to an unaffiliated party or to a separate corporate affiliate. Under the 1999 Settlement Agreement,

APS received a waiver to allow transfer of its generation and other competitive assets and services to affiliates no later than December 31, 2002. See "1999 Settlement Agreement" above for a discussion of the planned timing of the transfer.

1996 Regulatory Agreement. In April 1996, the ACC approved a regulatory agreement between the ACC Staff and APS. Based on the price reduction formula authorized in the agreement, the ACC approved retail price decreases (approximate) as follows (dollars in millions):

Annual Electric Revenue Decrease	Percentage Decrease	Effective Date
$49	3.4%	July 1, 1996
$18	1.2%	July 1, 1997
$17	1.1%	July 1, 1998
$11	0.7%	July 1, 1999 (a)

(a) Included in the first rate reduction under the 1999 Settlement Agreement (see above).

The regulatory agreement also required that we infuse $200 million of common equity into APS in annual payments of $50 million from 1996 through 1999. All of these equity infusions were made by December 31, 1999.

Legislation. In May 1998, a law was enacted to facilitate implementation of retail electric competition in Arizona. The law includes the following major provisions:

- Arizona's largest government-operated electric utility (Salt River Project) and, at their option, smaller municipal electric systems must (i) make at least 20% of their 1995 retail peak demand available to electric service providers by December 31, 1998 and for all retail customers by December 31, 2000; (ii) decrease rates by at least 10% over a ten-year period beginning as early as January 1, 1991; (iii) implement procedures and public processes comparable to those already applicable to public service corporations for establishing the terms, conditions, and pricing of electric services as well as certain other decisions affecting retail electric competition;

- describes the factors which form the basis of consideration by Salt River Project in determining stranded costs; and

- metering and meter reading services must be provided on a competitive basis during the first two years of competition only for customers having demands in excess of one MW (and that are eligible for competitive generation services), and thereafter for all customers receiving competitive electric generation.

General

APS cannot accurately predict the impact of full retail competition on its financial position, cash flows, results of operations, or liquidity. As competition in the electric industry continues to evolve, APS will continue to evaluate strategies and alternatives that will position it to compete in the new regulatory environment.

Federal

The 1992 Energy Act and recent rulemakings by FERC have promoted increased competition in the wholesale energy markets. APS does not expect these rules to have a material impact on its financial statements.

Several electric utility industry restructuring bills will undoubtedly be introduced during the current congressional session. Several of these bills are written to allow consumers to choose their electricity suppliers beginning in 2001 and beyond. These bills and other bills are expected to be introduced, and ongoing discussions at the federal level suggest a wide range of opinion that will need to be narrowed before any comprehensive restructuring of the electric utility industry can occur.

4. Income Taxes

Income Taxes

Certain assets and liabilities are reported differently for income tax purposes than they are for financial statements. The tax effect of these differences is recorded as deferred taxes. We calculate deferred taxes using the current income tax rates.

APS has recorded a regulatory asset related to income taxes on its Balance Sheet in accordance with SFAS No. 71. This regulatory asset is for certain temporary differences, primarily the allowance for equity funds used during construction. APS amortizes this amount as the differences reverse. In accordance with the 1999 Settlement Agreement, APS is continuing to accelerate its amortization of the regulatory asset for income taxes over an eight-year period that will end June 30, 2004 (see Note 1). We are including this accelerated amortization in depreciation and amortization expense on the Statements of Income. The components of income tax expense for continuing operations are:

(dollars in thousands)

	Year Ended December 31,		
	2000	1999	1998
Current			
Federal	$ 189,779	$ 171,491	$ 105,922
State	42,306	37,501	40,621
Total current	232,085	208,992	146,543
Deferred	(8,973)	(17,413)	41,566
ITC amortization	740	(23,514)	(23,516)
Total expense	$ 223,852	$ 168,065	$ 164,593

The following chart compares pretax income at the 35% federal income tax rate to income tax expense:

(dollars in thousands)

	Year Ended December 31,		
	2000	1999	1998
Federal income tax expense at 35% statutory rate	$ 184,164	$ 153,243	$ 142,620
Increases (reductions) in tax expense resulting from:			
Tax under book depreciation	12,328	14,575	17,848
Preferred stock dividends of APS	--	356	3,396
ITC amortization	740	(23,514)	(23,516)
State income tax net of federal income tax benefit	23,555	23,030	22,764
Other	3,065	375	1,481
Income tax expense	$ 223,852	$ 168,065	$ 164,593

The components of the net deferred income tax liability were as follows:

(dollars in thousands)

	Year Ended December 31,	
	2000	1999
DEFERRED TAX ASSETS		
Deferred gain on Palo Verde Unit 2 sale/leaseback	$ 27,056	$ 29,446
Other	89,416	133,748
Total deferred tax assets	116,472	163,194
DEFERRED TAX LIABILITIES		
Plant-related	1,081,637	1,104,769
Regulatory asset for income taxes	172,082	234,117
Total deferred tax liabilities	1,253,719	1,338,886
Accumulated deferred income taxes – net	$1,137,247	$1,175,692

Investment Tax Credit

Because of a 1994 rate settlement agreement, we accelerated amortization of substantially all of our ITCs over a five-year period (1995-1999).

Income Tax Benefit From Discontinued Operations

In 1999, the income tax benefit from discontinued operations for $38 million resulted from resolution of tax issues related to a former subsidiary, MeraBank, A Federal Savings Bank.

5. Lines of Credit

APS had committed lines of credit with various banks of $250 million at December 31, 2000 and $350 million at December 31, 1999, which were available either to support the issuance of commercial paper or to be used for bank borrowings. The commitment fees at December 31, 2000 and 1999 for these lines of credit ranged from 0.09% to 0.125% per annum. APS had no long-term bank borrowings at December 31, 2000 and $50 million outstanding at December 31, 1999.

APS' commercial paper borrowings outstanding were $82 million at December 31, 2000 and $38 million at December 31, 1999. The weighted average interest rate on commercial paper borrowings was 6.64% for the year ended December 31, 2000 and 5.33% for the year ended December 31, 1999. By Arizona statute, APS' short-term borrowings cannot exceed 7% of its total capitalization unless approved by the ACC.

Pinnacle West had a revolving line of credit of $250 million at December 31, 2000 and 1999. The commitment fees were 0.15% in 2000 and 0.10% in 1999. Outstanding amounts at December 31, 2000 were $188 million and at December 31, 1999 were $56 million.

SunCor had revolving lines of credit totalling $120 million at December 31, 2000 and $100 million at December 31, 1999. The commitment fees were 0.125% in 2000 and 1999. SunCor had $110 million outstanding at December 31, 2000 and $94 million outstanding at December 31, 1999.

6. Long-Term Debt

Borrowings under the APS mortgage bond indenture are secured by substantially all utility plant; APS also has unsecured debt; SunCor's debt is collateralized by interests in certain real property; Pinnacle West's debt is unsecured. The following table presents the components of consolidated long-term debt outstanding at December 31, 2000 and December 31, 1999:

PINNACLE WEST CAPITAL CORPORATION
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

(dollars in thousands)

	Maturity Dates (a)	Interest Rates	December 31, 2000	December 31, 1999
APS				
First mortgage bonds	2000	5.75%	$ --	$ 100,000
	2002	8.125%	125,000	125,000
	2004	6.625%	80,000	80,000
	2020	10.25%	--	100,550
	2021	9.5%	45,140	45,140
	2021	9%	72,370	72,370
	2023	7.25%	70,650	70,650
	2024	8.75%	121,668	121,668
	2025	8%	33,075	47,075
	2028	5.5%	25,000	25,000
	2028	5.875%	154,000	154,000
Unamortized discount and premium			(5,993)	(5,860)
Pollution control bonds	2024-2034	Adjustable rate(b)	476,860	476,860
Funds held in trust account for certain pollution control bonds			--	(1,236)
Collateralized loan	2000	5.375%-6.125%	--	10,000
Unsecured notes	2004	5.875%	125,000	125,000
Unsecured notes	2005	6.25%	100,000	100,000
Unsecured notes	2005	7.625%	300,000	--
Floating rate notes	2001	Adjustable rate(c)	250,000	250,000
Senior notes (d)	2006	6.75%	83,695	83,695
Debentures	2025	10%	--	75,000
Bank loans	2003	Adjustable rate(e)	--	50,000
Capitalized lease obligation	2000	7.48%(f)	--	7,199
Capitalized lease obligation	2001-2003	7.75%	709	--
			2,057,174	2,112,111
SUNCOR				
Revolving credit	2002-2003	(g)	110,000	94,000
Notes payable	2001-2006	(h)	8,163	3,404
Bonds payable	2039	5.85%	5,215	5,335
			123,378	102,739
PINNACLE WEST				
Revolving credit	2001	(i)	188,000	56,000
Senior notes	2001-2003	(j)	50,000	50,000
			238,000	106,000
Total long-term debt			2,418,552	2,320,850
Less current maturities			463,469	114,798
Total long-term debt less current maturities			$1,955,083	$2,206,052

(a) This schedule does not reflect the timing of redemptions that may occur prior to maturity.
(b) The weighted-average rate for the year ended December 31, 2000 was 4.06% and for December 31, 1999 was 3.15%. Changes in short-term interest rates would affect the costs associated with this debt.
(c) The weighted-average rate for the year ended December 31, 2000 was 7.33% and for December 31, 1999 was 6.8525%.
(d) APS currently has outstanding $84 million of first mortgage bonds (senior note mortgage bonds) issued to the senior note trustee as collateral for the senior notes. The senior note mortgage bonds have the same interest rate, interest payment dates, maturity, and redemption provisions as the senior notes. APS' payments of principal, premium, and/or interest on the senior notes satisfy its corresponding payment obligations on the senior note mortgage bonds. As long as the senior note mortgage bonds secure the senior notes, the senior notes will effectively rank equally with the first mortgage bonds. When APS repays all of its first mortgage bonds, other than those that secure senior notes, the senior note mortgage bonds will no longer secure the senior notes and will cease to be outstanding.
(e) The weighted-average rate for the year ended December 31, 2000 was 6.53% and for December 31, 1999 was 5.5%. Changes in short-term interest rates would affect the costs associated with this debt. At December 31, 2000, we had no long-term bank borrowings outstanding.
(f) Represents the present value of future lease payments (discounted at an interest rate of 7.48%) on a combined cycle plant that was sold and leased back. The capital lease was paid off early and the related asset was purchased in December 2000 (See Note 10).
(g) The weighted-average rate at December 31, 2000 was 8.61% and at December 31, 1999 was 8.51%. Interest for 2000 and 1999 was based on LIBOR plus 2% or prime plus 0.5%.
(h) Multiple notes primarily with variable interest rates based mostly on the lenders' prime plus 1.75% and lenders' prime plus .25%.
(i) The weighted-average rate at December 31, 2000 was 7.51% and at December 31, 1999 was 6.825%. Interest for 2000 was based on LIBOR plus 0.75% and interest for 1999 was based on LIBOR plus 0.33%.
(j) Includes two series of notes: $25 million at 6.62% due 2001, and $25 million at 6.87% due 2003.

The following is a list of principal payments due on total long-term debt and sinking fund requirements through 2005:

- $463 million in 2001;
- $162 million in 2002;
- $99 million in 2003;
- $205 million in 2004; and
- $400 million in 2005.

First mortgage bondholders share a lien on substantially all utility plant assets (other than nuclear fuel and transportation equipment). The mortgage bond indenture restricts the payment of common stock dividends under certain conditions. These conditions did not exist at December 31, 2000.

7. Preferred Stock of APS

On March 1, 1999, APS redeemed all of its preferred stock. Preferred stock balances of APS at December 31, 2000 and 1999 were zero. Redeemable preferred stock transactions of APS during each of the three years in the period ended December 31, 2000 are as follows:

(dollars in thousands)

	Number of Shares	Par Value Amount
Balance, December 31, 1997	291,098	$ 29,110
Retirements		
$10.00 Series U	(197,087)	(19,709)
Balance, December 31, 1998	94,011	9,401
Retirements		
$10.00 Series U	(94,011)	(9,401)
Balance, December 31, 1999	--	--
Balance, December 31, 2000	--	$ --

8. Common Stock

Our common stock issued during each of the three years in the period ended December 31, 2000 is as follows:

(dollars in thousands)

	Number of Shares	Amount
Balance, December 31, 1997	84,824,947	$1,553,771
Common stock expense	--	(3,128)(a)
Balance, December 31, 1998	84,824,947	1,550,643
Common stock expense	--	(13,194)(a)
Balance, December 31, 1999	84,824,947	1,537,449
Common stock expense	--	(4,618)
Balance, December 31, 2000	84,824,947	$1,532,831

(a) Including premiums and expenses of preferred stock issues of APS.

9. Retirement Plans and Other Benefits

Pension Plans

Through 1999, Pinnacle West and its subsidiaries each sponsored defined benefit pension plans for their own employees. As of January 1, 2000, these plans were consolidated and now a single pension plan is sponsored by Pinnacle West for the employees of Pinnacle West and its subsidiaries. A defined benefit plan specifies the amount of benefits a plan participant is to receive using information about the participant. The plan covers nearly all of our employees. Our employees do not contribute to this plan. Generally, we calculate the benefits under these plans based on age, years of service, and pay. We fund the plan by contributing at least the minimum amount required under Internal Revenue Service regulations but no more than the maximum tax-deductible amount. The assets in the plan at December 31, 2000 were mostly domestic and international common stocks and bonds and real estate.

Pension expense, including administrative costs, was:

- $2 million in 2000;
- $4 million in 1999; and
- $11 million in 1998.

The following table shows the components of net pension cost before consideration of amounts capitalized or billed to others:

(dollars in thousands)

	2000	1999	1998
Service cost - benefits earned during the period	$ 24,955	$ 24,982	$ 24,817
Interest cost on projected benefit obligation	58,361	52,905	51,524
Expected return on plan assets	(77,231)	(68,335)	(54,513)
Amortization of:			
Transition asset	(3,227)	(3,226)	(3,226)
Prior service cost	2,078	2,078	2,078
Net actuarial gain	(1,633)	--	--
Net periodic pension cost	$ 3,303	$ 8,404	$ 20,680

The following table shows a reconciliation of the funded status of the plans to the amounts recognized in the balance sheets:

(dollars in thousands)

	2000	1999
Funded status - pension plan assets more than (less than) projected benefit obligation	$ (20,730)	$ 37,275
Unrecognized net transition asset	(16,781)	(20,008)
Unrecognized prior service cost	18,558	20,636
Unrecognized net actuarial gains	(23,816)	(101,153)
Net pension liability recognized in the balance sheets	$ (42,769)	$ (63,250)

The following table sets forth the defined benefit pension plans' change in projected benefit obligation for the plan years 2000 and 1999:

(dollars in thousands)

	2000	1999
Projected pension benefit obligation at beginning of year	$ 742,638	$ 731,305
Service cost	24,955	24,982
Interest cost	58,361	52,905
Benefit payments	(30,568)	(29,694)
Actuarial (gains)/losses	540	(36,860)
Projected pension benefit obligation at end of year	$ 795,926	$ 742,638

The following table sets forth the defined benefit pension plans' change in the fair value of plan assets for the plan years 2000 and 1999:

(dollars in thousands)

	2000	1999
Fair value of pension plan assets at beginning of year	$ 779,913	$ 690,271
Actual return on plan assets	1,851	93,977
Employer contributions	24,000	25,359
Benefit payments	(30,568)	(29,694)
Fair value of pension plan assets at end of year	$ 775,196	$ 779,913

We made the assumptions below to calculate the pension liability:

	2000	1999
Discount rate	7.75%	7.75%
Rate of increase in compensation levels	4.25%	4.25%
Expected long-term rate of return on assets	10.00%	10.00%

Employee Savings Plan Benefits

Through 1999, Pinnacle West and its subsidiaries each sponsored defined contribution savings plans for their own employees. As of January 1, 2000, these plans were consolidated and now a single defined contribution savings plan is sponsored by Pinnacle West for the employees of Pinnacle West and its subsidiaries. In a defined contribution plan, the benefits a participant will receive result from regular contributions they make to a participant account. Under this plan, we make matching contributions to participant accounts. We recorded expenses for this plan of approximately $4 million for 2000, 1999, and 1998.

Postretirement Plans

We provide medical and life insurance benefits to retired employees. Employees must retire to become eligible for these retirement benefits, which are based on years of service and age. For the medical insurance plans, retirees make contributions to cover a portion of the plan costs. For the life insurance plan, retirees do not make contributions to cover a portion of the plan costs. We retain the right to change or eliminate these benefits.

Funding is based upon actuarially determined contributions that take tax consequences into account. Plan assets consist primarily of domestic stocks and bonds. The postretirement benefit expense was:

- $ 3 million for 2000;
- $ 7 million for 1999; and
- $ 9 million for 1998.

The following table shows the components of net periodic postretirement benefit costs before consideration of amounts capitalized or billed to others:

(dollars in thousands)

	2000	1999	1998
Service cost - benefits earned during the period	$ 8,613	$ 8,939	$ 7,890
Interest cost on accumulated benefit obligation	19,315	17,366	15,763
Expected return on plan assets	(22,381)	(18,454)	(12,001)
Amortization of:			
Transition obligation	7,698	7,698	7,698
Net actuarial gains	(7,983)	(5,117)	(2,952)
Net periodic postretirement benefit cost	$ 5,262	$ 10,432	$ 16,398

The following table shows a reconciliation of the funded status of the plan to the amounts recognized in the balance sheets:

(dollars in thousands)

	2000	1999
Funded status - postretirement plan assets more than (less than) projected benefit obligation	$ (14,851)	$ 25,549
Unrecognized net obligation at transition	92,446	100,145
Unrecognized net actuarial gains	(81,280)	(128,309)
Net postretirement amount recognized in the balance sheets	$ (3,685)	$ (2,615)

The following table sets forth the postretirement benefit plans' change in accumulated benefit obligation for the plan years 2000 and 1999:

(dollars in thousands)

	2000	1999
Accumulated postretirement benefit obligation at beginning of year	$ 231,989	$ 237,679
Service cost	8,613	8,939
Interest cost	19,315	17,366
Benefit payments	(8,905)	(8,761)
Actuarial (gains) losses	12,994	(23,234)
Accumulated postretirement benefit obligation at end of year	$ 264,006	$ 231,989

The following table sets forth the postretirement benefit plans' change in the fair value of plan assets for the plan years 2000 and 1999:

(dollars in thousands)

	2000	1999
Fair value of postretirement plan assets at beginning of year	$ 257,538	$ 213,410
Actual return on plan assets	(4,436)	42,975
Employer contributions	4,958	9,914
Benefit payments	(8,906)	(8,761)
Fair value of postretirement plan assets at the end of year	$ 249,154	$ 257,538

We made the assumptions below to calculate the postretirement liability:

	2000	1999
Discount rate	7.75%	7.75%
Expected long-term rate of return on assets - after tax	8.77%	8.77%
Initial health care cost trend rate - under age 65	7.00%	7.00%
Initial health care cost trend rate - age 65 and over	6.00%	6.00%
Ultimate health care cost trend rate (reached in the year 2002)	5.00%	5.00%

The following table shows the effect of a 1% increase or decrease in the health care cost trend rate:

(dollars in millions)

	1% increase	1% decrease
Effect on 2000 cost of postretirement benefits other than pensions	$ 5	$ (4)
Effect on the accumulated postretirement benefit obligation at December 31, 2000	43	(34)

10. Leases

In 1986, APS sold about 42% of its share of Palo Verde Unit 2 and certain common facilities in three separate sale leaseback transactions. APS accounts for these leases as operating leases. The gain of approximately $140 million was deferred and is being amortized to operations expense over 29.5 years, the original term of the leases. There are options to renew the leases for two additional years and to purchase the property for fair market value at the end of the lease terms. Consistent with the ratemaking treatment, an amount equal to the annual lease payments is included in rent expense. A regulatory asset is recognized for the difference between lease payments and rent expense calculated on a straight-line basis.

The average amounts to be paid for the Palo Verde Unit 2 leases are approximately $49 million per year for the years 2001-2015.

In accordance with the 1999 Settlement Agreement, APS is continuing to accelerate amortization of the regulatory asset for leases over an eight-year period that will end June 30, 2004 (see Note 1). The accelerated amortization is included in depreciation and amortization expense on the Statements of Income. The balance of this regulatory asset at December 31, 2000 was $33 million.

In December 2000, APS purchased Units 1, 2, and 3 of West Phoenix Power Plant. These units were previously reflected as a capital lease.

In addition, we lease certain land, buildings, equipment, and miscellaneous other items through operating rental agreements with varying terms, provisions, and expiration dates.

Total lease expense was $58 million in 2000, $52 million in 1999, and $55 million in 1998.

Estimated future minimum lease commitments, are approximately $67 million for each of the years 2001 to 2005 and $663 million thereafter.

11. Jointly-Owned Facilities

APS shares ownership of some of its generating and transmission facilities with other companies. The following table shows APS' interest in those jointly-owned facilities at December 31, 2000. APS' share of operating and maintaining these facilities is included in the income statement in operations and maintenance expense.

	Percent Owned by Company	Plant in Service	Accumulated Depreciation	Construction Work in Progress
Generating Facilities:		(dollars in thousands)		
Palo Verde Nuclear Generating Station Units 1 and 3	29.1%	$1,824,480	$814,693	$7,414
Palo Verde Nuclear Generating Station Unit 2 (see Note 10)	17.0%	571,573	265,571	29,593
Four Corners Steam Generating Station Units 4 and 5	15.0%	152,717	75,797	--
Navajo Steam Generating Station Units 1, 2, and 3	14.0%	231,509	99,623	4,899
Cholla Steam Generating Station Common Facilities (a)	62.8%(b)	73,382	40,023	686
Transmission Facilities:				
ANPP 500KV System	35.8%(b)	67,987	22,813	--
Navajo Southern System	31.4%(b)	27,290	17,804	55
Palo Verde-Yuma 500KV System	23.9%(b)	9,712	3,844	1
Four Corners Switchyards	27.5%(b)	3,071	1,925	--
Phoenix-Mead System	17.1%(b)	36,418	2,681	--
Palo Verde – Estrella 500KV System	50.0%(b)	--	--	610

(a) PacifiCorp owns Cholla Unit 4 and APS operates the unit for them. The common facilities at the Cholla Plant are jointly-owned.

(b) Weighted average of interests.

12. Commitments and Contingencies

Litigation

We are party to various claims, legal actions, and complaints arising in the ordinary course of business. In our opinion, the ultimate resolution of these matters will not have a material adverse effect on our financial statements.

Power Service Agreement

APS is a party to a power service agreement with Citizens Communications Company (Citizens) under which APS supplies Citizens with power. By letter dated March 7, 2001, Citizens advised APS that it believes APS has overcharged Citizens by over $50 million under the agreement since the summer of 2000. APS believes that its charges to Citizens under the agreement are fully in accordance with the terms of the agreement and APS will vigorously defend any contrary claims raised by Citizens.

Palo Verde Nuclear Generating Station

Pursuant to the Nuclear Waste Policy Act of 1982 , the DOE must accept and dispose of all spent nuclear fuel and other high-level radioactive wastes generated by domestic power reactors. The United States Nuclear Regulatory Commission (NRC) requires operators of nuclear power reactors to enter into spent fuel disposal contracts with the DOE. Under the Nuclear Waste Policy Act

of 1982, the DOE was to develop a permanent repository for the storage and disposal of spent nuclear fuel by 1998. The DOE has announced that such a permanent repository cannot be completed before 2010, and that it does not intend to begin accepting spent fuel prior to that date.

In November 1997, the United States Court of Appeals for the District of Columbia Circuit (D.C. Circuit) issued a decision precluding the DOE from excusing its own delay, but refused to order the DOE to begin accepting spent nuclear fuel. Based on this decision, a number of utilities filed damages actions against DOE in the Court of Federal Claims. In decisions that became final in December 2000, the United States Court of Appeals for the Federal Circuit held that utilities do not have to exhaust the DOE administrative claims before filing lawsuits for damages against the DOE in the Court of Federal Claims.

APS has existing fuel storage pools at Palo Verde and is in the process of completing construction of a new facility for on-site dry storage of spent fuel. With the existing storage pools and the addition of the new facility, APS believes that spent fuel storage or disposal methods will be available for use by Palo Verde to allow its continued operation through the term of the operating license for each Palo Verde unit.

Although some low-level waste has been stored on-site in a low-level waste facility, APS is currently shipping low-level waste to off-site facilities. APS currently believes that interim low-level waste storage methods are or will be available for use by Palo Verde to allow its continued operation and to safely store low-level waste until a permanent disposal facility is available.

APS currently estimates that it will incur $113 million (in 2000 dollars) over the life of Palo Verde for its share of the costs related to the on-site interim storage of spent nuclear fuel. As of December 31, 2000, APS had recorded a liability and regulatory asset of $40 million for on-site interim nuclear fuel storage costs related to nuclear fuel burned to date.

The Palo Verde participants have insurance for public liability resulting from nuclear energy hazards to the full limit of liability under federal law. This potential liability is covered by primary liability insurance provided by commercial insurance carriers in the amount of $200 million and the balance by an industry-wide retrospective assessment program. If losses at any nuclear power plant covered by the programs exceed the accumulated funds, APS could be assessed retrospective premium adjustments. The maximum assessment per reactor under the program for each nuclear incident is approximately $88 million, subject to an annual limit of $10 million per incident. Based upon our interest in the three Palo Verde units, our maximum potential assessment per incident for all three units is approximately $77 million, with an annual payment limitation of approximately $9 million.

The Palo Verde participants maintain "all risk" (including nuclear hazards) insurance for property damage to, and decontamination of, property at Palo Verde in the aggregate amount of $2.75 billion, a substantial portion of which must first be applied to stabilization and decontamination. APS has also secured insurance against portions of any increased cost of generation or purchased power and business interruption resulting from a sudden and unforeseen outage of any of the three units. The insurance coverage discussed in this and the previous paragraph is subject to certain policy conditions and exclusions.

Fuel and Purchased Power Commitments

APS is a party to various fuel and purchased power contracts with terms expiring from 2001 through 2021 that include required purchase provisions. APS estimates its contract requirements to be approximately $277 million in 2001; $145 million in 2002; $90 million in 2003; $83 million in 2004; and $55 million in 2005. However, this amount may vary significantly pursuant to certain provisions in such contracts that permit APS to decrease its required purchases under certain circumstances.

APS must reimburse certain coal providers for amounts incurred for coal mine reclamation. APS estimates its share of the total obligation to be about $103 million. The portion of the coal mine reclamation obligation related to coal already burned is about $58 million at December 31, 2000 and is included in deferred credits-other in the Balance Sheet.

A regulatory asset has been established for amounts not yet recovered from ratepayers. In accordance with the 1999 Settlement Agreement with the ACC, APS is continuing to accelerate the amortization of the regulatory asset for coal mine reclamation over an eight-year period that will end June 30, 2004. Amortization is included in depreciation and amortization expense on the Statements of Income. The balance of the regulatory asset at December 31, 2000 was about $32 million.

California Energy Market Issues

SCE and PG&E have publicly disclosed that their liquidity has been materially and adversely affected because of, among other things, their inability to pass on to ratepayers the prices each has paid for energy and ancillary services procured through the PX and the ISO.

We are closely monitoring developments in the California energy market and the potential impact of these developments on us and our subsidiaries. We have evaluated, among other things, SCE's role as a Palo Verde and Four Corners participant; APS' transactions with the PX and the ISO; contractual relationships with SCE and PG&E; APS Energy Services' retail transactions involving SCE and PG&E; and power marketing exposures. Based upon the financial transactions to date, we do not believe the foregoing matters will have a material adverse effect on our financial position or liquidity. We cannot predict with certainty, however, the impact that any future resolution or attempted resolution, of the California energy market situation may have on us or our subsidiaries or the regional energy market in general.

See "Generation Expansion" below for a discussion of Pinnacle West Energy's agreement to purchase SCE's Palo Verde interest.

Construction Program

Consolidated capital expenditures in 2001 are estimated at:

CAPITAL EXPENDITURES
(dollars in millions)

	2001
APS	$ 455
Pinnacle West Energy	659
SunCor	75
Other	21
Total	$ 1,210

Generation Expansion

Pinnacle West Energy has announced plans to build and acquire up to 2,800 MW of generating capacity from 2001-2006 at an estimated cost of about $1.3 billion.

Pinnacle West Energy is also considering additional expansion over the next several years, which may result in additional expenditures. Pinnacle West Energy's expenditures are expected to be funded through internally generated cash and debt issued directly by Pinnacle West Energy, as well as capital infusions from Pinnacle West's internally generated cash and debt proceeds.

Pinnacle West Energy is currently planning a 650-megawatt expansion of the West Phoenix Power Plant and the construction of a natural gas-fired electric generating station of up to four, 530 MW units, near Palo Verde, called Redhawk . Construction on the 120 MW West Phoenix Unit 4 began in June 2000, with commercial operation of the unit expected in the summer of 2001. Pinnacle West Energy expects construction to begin on the 530 MW Unit 5 in the fall of 2001, with commercial operation beginning in mid-2003. Construction began on the first two units of Redhawk in December 2000, and commercial operation is scheduled for the summer of 2002.

Pinnacle West Energy has entered into an agreement with NPC to purchase NPC's 72 MW gas-fired Harry Allen Power Station about 30 miles northeast of Las Vegas, Nevada, for a net purchase price, after adjustments for purchased power commitments, of approximately $65.2 million. The purchase is subject to filing with and/or approval of various regulatory agencies, including FERC and the NPUC. The filing with the NPUC was made in February 2001. NPC will have the right, but not the obligation, to purchase the output from the Harry Allen plant at market rates, subject to a floor and a cap. As demand grows in the region during the next five years, Pinnacle West Energy expects to add a 480 MW gas-fired, combined cycle unit to the site. The Governor of Nevada has recently requested that the NPUC reexamine the divestiture of generation. The timing and result of any action by the NPUC is not yet known.

On April 27, 2000, Pinnacle West Energy entered into two separate agreements with SCE to purchase SCE's 15.8% ownership interest in Palo Verde and its 48% ownership interest in the Four Corners Power Plant. Consistent with the agreements, on January 5, 2001, Pinnacle West Energy informed SCE that it would not match a competing bid that SCE received for its Four Corners ownership interest. Therefore, Pinnacle West Energy will not purchase SCE's Four Corners interest under the April 2000 agreement unless the Palo Verde transaction closes, the competing Four Corners transaction does not close, and Pinnacle West Energy acquires the Four Corners interest at the original $300 million purchase price as a standby purchaser. SCE did not receive any qualified competing bids for its Palo Verde ownership interest, which Pinnacle West Energy agreed to purchase for $250 million. However, recently-enacted California legislation provides that "no facility for the generation of electricity owned by a public utility may be disposed of prior to January 1, 2006." Unless this California law is amended, Pinnacle West Energy would not be able to acquire SCE's Palo Verde ownership interest pursuant to the original April 2000 agreement.

13. Nuclear Decommissioning Costs

APS recorded $11 million for nuclear decommissioning expense in each of the years 2000, 1999, and 1998. APS estimates it will cost about $1.8 billion ($493 million in 2000 dollars) to decommission its share of the three Palo Verde units. The decommissioning costs are expected to be

incurred over a 14-year period beginning in 2024. APS charges decommissioning costs to expense over each unit's operating license term and includes them in the accumulated depreciation balance until each unit is retired. Nuclear decommissioning costs are recovered in rates.

APS' current estimates are based on a 1998 site-specific study for Palo Verde that assumes the prompt removal/dismantlement method of decommissioning. An independent consultant prepared this study. APS is required to update the study every three years.

To fund the costs APS expects to incur to decommission the plant, APS established external decommissioning trusts in accordance with NRC regulations. The trust accounts are reported in investments and other assets on the Consolidated Balance Sheets at their market value of $205 million at December 31, 2000 and $176 million at December 31, 1999. APS invests the trust funds primarily in fixed income securities and domestic stock and classifies them as available for sale. Realized and unrealized gains and losses are reflected in accumulated depreciation.

See Note 2 for a proposed accounting standard on accounting for certain liabilities related to closure or removal of long-lived assets.

14. Selected Quarterly Financial Data (Unaudited)

Consolidated quarterly financial information for 2000 and 1999 is as follows:

(dollars in thousands, except per share amounts)

	2000			
QUARTER ENDED	March 31	June 30	September 30	December 31
Operating revenues				
Electric	$ 446,228	$ 720,174	$1,567,960	$ 797,448
Real estate	41,889	36,374	39,396	40,706
Operating income (a)	$ 96,271	$ 201,153	$ 256,001	$ 122,546
Net income	$ 54,070	$ 89,901	$ 116,049	$ 42,312
Earnings per average common share outstanding				
Net income – basic	$ 0.64	$ 1.06	$ 1.37	$ 0.50
Net income – diluted	$ 0.64	$ 1.06	$ 1.37	$ 0.50
Dividends declared per share	$ 0.35	$ 0.35	$ 0.35	$ 0.375

(dollars in thousands, except per share amounts)

	1999			
QUARTER ENDED	March 31	June 30	September 30	December 31
Operating revenues				
Electric	$ 413,983	$ 511,434	$ 867,630	$ 500,137
Real estate	24,533	32,697	26,640	46,299
Operating income (a)	$ 91,599	$ 148,968	$ 240,294	$ 97,916
Income from continuing Operations	$ 30,690	$ 68,702	$ 125,579	$ 44,801
Income tax benefit from discontinued operations	--	--	38,000	--
Extraordinary charge - net of income tax	--	--	(139,885)	--
Net income	$ 30,690	$ 68,702	$ 23,694	$ 44,801
Earnings (loss) per average common share outstanding				
Continuing operations – basic	$ 0.36	$ 0.81	$ 1.48	$ 0.53
Discontinued operations – Basic	--	--	0.45	--
Extraordinary charge – basic	--	--	(1.65)	--
Net Income – basic	$ 0.36	$ 0.81	$ 0.28	$ 0.53
Continuing operations – diluted	$ 0.36	$ 0.81	$ 1.48	$ 0.53
Discontinued operations – Diluted	--	--	0.45	--
Extraordinary charge – diluted	--	--	(1.65)	--
Net Income – diluted	$ 0.36	$ 0.81	$ 0.28	$ 0.53
Dividends declared per share (b)	$ 0.325	$ 0.65	$ --	$ 0.35

(a) Electric revenues are seasonal in nature, with the peak sales periods generally occurring during the summer months. Comparisons among quarters of a year may not represent overall trends and changes in operations.

(b) Dividends for the quarter ending September 30, 1999 were declared in June 1999.

15. Fair Value of Financial Instruments

We believe that the carrying amounts of our cash equivalents and commercial paper are reasonable estimates of their fair values at December 31, 2000 and 1999 due to their short maturities.

We hold investments in debt and equity securities for purposes other than trading. The December 31, 2000 and 1999 fair values of such investments, which we determine by using quoted market values, approximate their carrying amount.

The carrying value of our long-term debt (excluding a capitalized lease obligation) was $2.42 billion on December 31, 2000, with an estimated fair value of $2.48 billion. On December 31, 1999, the carrying value of our long-term debt (excluding a capitalized lease obligation) was $2.31 billion, with an estimated fair value of $2.29 billion. The fair value estimates are based on quoted market prices of the same or similar issues.

16. Earnings Per Share

The following table presents earnings per average common share outstanding (EPS):

	2000	1999	1998
Basic EPS:			
Continuing operations	$ 3.57	$ 3.18	$ 2.87
Discontinued operations	--	0.45	--
Extraordinary charge	--	(1.65)	--
Net income	$ 3.57	$ 1.98	$ 2.87
Diluted EPS:			
Continuing operations	$ 3.56	$ 3.17	$ 2.85
Discontinued operations	--	0.45	--
Extraordinary charge	--	(1.65)	--
Net income	$ 3.56	$ 1.97	$ 2.85

Dilutive stock options increased average common shares outstanding by 202,738 shares in 2000, 291,392 shares in 1999, and 571,728 shares in 1998. Total average common shares outstanding for the purposes of calculating diluted earnings per share were 84,935,282 shares in 2000, 85,008,527 shares in 1999, and 85,345,946 shares in 1998.

Options to purchase 517,614 shares of common stock were outstanding at December 31, 2000 but were not included in the computation of diluted EPS because the options' exercise price was greater than the average market price of the common shares. Options to purchase shares of common stock that were not included in the computation of diluted EPS were 506,734 at December 31, 1999 and 244,200 at December 31, 1998.

17. Stock-Based Compensation

Pinnacle West offers two stock incentive plans for our and our subsidiaries' officers and key employees.

The plan provides for the granting of new options (which may be non-qualified stock options or incentive stock options) of up to 3.5 million shares at a price per option not less than the fair market value on the date the option is granted. Options vest one-third of the grant per year beginning one year after the date the option is granted and expire ten years from the date of the grant. The plan also provides for the granting of any combination of shares of restricted stock, stock appreciation rights or dividend equivalents.

The awards outstanding under the incentive plans at December 31, 2000 approximate 1,569,171 non-qualified stock options, 193,992 shares of restricted stock, and no incentive stock options, stock appreciation rights or dividend equivalents.

The FASB issued SFAS No. 123, "Accounting for Stock-Based Compensation" which was effective beginning in 1996. The statement encourages, but does not require, that a company record compensation expense based on the fair value of options granted (the fair value method). We continue to recognize expense based on Accounting Principles Board Opinion No. 25, "Accounting for Stock Issued to Employees."

If we had recorded compensation expense based on the fair value method, our net income and earnings per share would have been reduced to the following pro forma amounts:

	(dollars in thousands) 2000	1999	1998
Net income			
As reported	$ 302,332	$ 167,887	$ 242,892
Pro forma (fair value method)	$ 301,102	$ 166,913	$ 242,177
Earnings per share – basic			
As reported	$ 3.57	$ 1.98	$ 2.87
Pro forma (fair value method)	$ 3.55	$ 1.97	$ 2.86

In order to present the pro forma information above, we calculated the fair value of each fixed stock option in the incentive plans using the Black-Scholes option-pricing model. The fair value was calculated based on the date the option was granted. The following weighted-average assumptions were also used in order to calculate the fair value of the stock options:

	2000	1999	1998
Risk-free interest rate	5.81%	5.68%	4.54%
Dividend yield	3.48%	3.33%	3.03%
Volatility	32.00%	20.50%	18.80%
Expected life (months)	60	60	60

The following table is a summary of the status of our stock option plans as of December 31, 2000, 1999, and 1998 and changes during the years ending on those dates:

	2000 Shares	2000 Weighted Average Exercise Price	1999 Shares	1999 Weighted Average Exercise Price	1998 Shares	1998 Weighted Average Exercise Price
Outstanding at Beginning of year	1,441,124	$33.45	1,563,512	$27.95	1,554,631	$24.38
Granted	451,450	43.28	458,450	35.95	244,200	46.78
Exercised	(283,819)	20.90	(516,838)	18.19	(217,317)	23.09
Forfeited	(39,584)	39.86	(64,000)	40.36	(18,002)	33.42
Outstanding at end of year	1,569,171	37.55	1,441,124	33.45	1,563,512	27.95
Options exercisable at year-end	831,537	34.37	835,381	29.69	1,106,165	22.04
Weighted average fair value of options granted during the year		11.81		7.05		8.15

The following table summarizes information about our stock option plans at December 31, 2000:

Exercise Prices Per Share	Options Outstanding	Weighted Average Remaining Contract Life (Years)	Options Exercisable
$10.06	7,000	.50	7,000
15.75	10,000	.90	10,000
17.68	4,900	1.10	4,900
18.13	14,000	1.50	14,000
19.00	58,618	3.90	58,618
19.56	15,000	1.90	15,000
22.13	33,250	3.00	33,250
23.25	14,000	2.50	14,000
27.16	20,000	9.20	5,000
27.44	84,918	4.90	84,918
31.44	87,335	5.90	87,335
34.66	327,113	8.90	118,124
36.56	5,000	8.80	2,083
39.75	170,636	7.00	170,636
41.00	70,000	8.10	44,722
44.03	431,450	9.90	11,985
46.78	215,951	7.90	149,966
$10.06-$46.78	1,569,171		831,537

18. Business Segments

We have two principal business segments (determined by products, services and regulatory environment) which consist of the transmission and distribution of electricity and wholesale activities (delivery business segment) and the generation of electricity (generation business segment). The other amounts include activity relating to the parent company and other subsidiaries including APS Energy Services, SunCor and El Dorado. Eliminations primarily relate to intersegment sales of electricity. Financial data for the business segments is provided as follows:

Business Segments For Year Ended December 31, 2000
(dollars in thousands)

	Generation	Delivery	Other	Eliminations	Total
Operating revenues	$ 990,415	$3,531,810	$ 158,365	$ (990,415)	$3,690,175
Operating expense	600,389	2,871,329	138,677	(990,415)	2,619,980
Operating margin	390,026	660,481	19,688	--	1,070,195
Depreciation and amortization	125,220	263,446	5,744	--	394,410
Interest	41,808	96,081	11,712	--	149,601
Pretax margin	222,998	300,954	2,232	--	526,184
Income taxes	87,828	134,692	1,332	--	223,852
Earnings for common stock	$ 135,170	$ 166,262	$ 900	$ --	$ 302,332
Total assets	$2,606,046	$4,068,510	$ 474,595	$ --	$7,149,151
Capital expenditures	$ 379,761	$ 285,455	$ 49,949	$ --	$ 715,165

Business Segments For Year Ended December 31, 1999
(dollars in thousands)

	Generation	Delivery	Other	Eliminations	Total
Operating revenues	$ 853,755	$2,292,798	$130,555	$(853,755)	$2,423,353
Operating expense	522,925	1,672,169	106,876	(853,755)	1,448,215
Operating margin	330,830	620,629	23,679	--	975,138
Depreciation and amortization	121,683	260,374	3,511	--	385,568
Interest and preferred stock dividend requirements	40,753	101,855	9,125	--	151,733
Pretax margin	168,394	258,400	11,043	--	437,837
Income taxes	47,976	111,512	8,577	--	168,065
Income tax benefit from discontinued operations – PNW	--	--	38,000	--	38,000
Extraordinary charge – net of income tax of $94,115	--	(139,885)	--	--	(139,885)
Earnings for common stock	$ 120,418	$ 7,003	$ 40,466	$ --	$ 167,887
Total assets	$2,342,291	$3,795,846	$470,369	$ --	$6,608,506
Capital expenditures	$ 110,798	$ 241,469	$126,581	$ --	$ 478,848

Business Segments For Year Ended December 31, 1998
(dollars in thousands)

	Generation	Delivery	Other	Eliminations	Total
Operating revenues	$ 858,340	$2,006,398	$ 124,188	$(858,340)	$2,130,586
Operating expense	522,696	1,414,753	104,061	(858,340)	1,183,170
Operating margin	335,644	591,645	20,127	--	947,416
Depreciation and amortization	135,406	241,168	3,105	--	379,679
Interest and preferred stock dividend requirements	37,045	108,670	14,537	--	160,252
Pretax margin	163,193	241,807	2,485	--	407,485
Income taxes	49,969	109,487	5,137	--	164,593
Earnings for common stock	$ 113,224	$ 132,320	$ (2,652)	$ --	$ 242,892
Total assets	$2,399,560	$3,993,740	$ 431,246	$ --	$6,824,546
Capital expenditures	$ 85,767	$ 241,638	$ 73,133	$ --	$ 400,538

PINNACLE WEST CAPITAL CORPORATION
SCHEDULE II – VALUATION AND QUALIFYING ACCOUNTS

Column A	Column B	Column C Additions		Column D	Column E
Description	Balance at beginning of period	Charged to cost and expenses	Charged to other accounts	Deductions[(a)]	Balance at end of Period
	(dollars in thousands)				
	YEAR ENDED DECEMBER 31, 2000				
Real Estate Valuation Reserves	$ 8,000	$ --	$ --	$ 6,000	$ 2,000
	YEAR ENDED DECEMBER 31, 1999				
Real Estate Valuation Reserves	$ 15,000	$ --	$ --	$ 7,000	$ 8,000
	YEAR ENDED DECEMBER 31, 1998				
Real Estate Valuation Reserves	$ 23,000	$ --	$ --	$ 8,000	$ 15,000

(a) Represents pro-rata allocations for sale of land.

ITEM 9. CHANGES IN AND DISAGREEMENTS WITH ACCOUNTANTS ON ACCOUNTING AND FINANCIAL DISCLOSURE

None.

PART III

ITEM 10. DIRECTORS AND EXECUTIVE OFFICERS OF THE REGISTRANT

Reference is hereby made to "Election of Directors" and to "Other Matters – Section 16(a) Beneficial Ownership Reporting Compliance" in the Company's Proxy Statement relating to the Annual Meeting of Shareholders to be held on May 23, 2001 (the 2001 Proxy Statement) and to the Supplemental Item --- "Executive Officers of the Registrant" in Part I of this report.

ITEM 11. EXECUTIVE COMPENSATION

Reference is hereby made to "Directors' Compensation," "Human Resources Committee Report on Executive Compensation," "Stock Performance Comparisons," "Executive Compensation," "Option Grants, Exercise, and Holdings," and "Executive Benefit Plans" in the 2001 Proxy Statement.

ITEM 12. SECURITY OWNERSHIP OF CERTAIN BENEFICIAL OWNERS AND MANAGEMENT

Reference is hereby made to "Security Ownership of Certain Beneficial Owners and Management" in the 2001 Proxy Statement.

ITEM 13. CERTAIN RELATIONSHIPS AND RELATED TRANSACTIONS

Reference is hereby made to "Executive Benefit Plans – Employment and Severance Arrangements" and "Other Matters -Business Relationship" in the 2001 Proxy Statement.

PART IV

ITEM 14. EXHIBITS, FINANCIAL STATEMENTS, FINANCIAL STATEMENT SCHEDULES, AND REPORTS ON FORM 8-K

Financial Statements

See the Index to Consolidated Financial Statements and Financial Statement Schedule in Part II, Item 8.

Exhibits Filed

Exhibit No.		*Description*
10.1[a]	—	2001 Management Variable Incentive Plan (Pinnacle West)
10.2[a]	—	2001 Senior Management Variable Incentive Plan (Pinnacle West)
10.3[a]	—	2001 Officer Variable Incentive Plan (Pinnacle West)
10.4[a]	—	2001 Management Variable Incentive Plan (APS)
10.5[a]	—	2001 Senior Management Variable Incentive Plan (APS)
10.6[a]	—	2001 Officers Variable Incentive Plan (APS)
10.7	—	Four Corners Project Co-Tenancy Agreement Amendment No. 6
10.8[a]	—	Sixth Amendment to Arizona Public Service Company Deferred Compensation Plan
12.1	—	Ratio of Earnings to Fixed Charges
21.1	—	Subsidiaries of the Company
23.1	—	Consent of Deloitte & Touche LLP

In addition to those Exhibits shown above, the Company hereby incorporates the following Exhibits pursuant to Exchange Act Rule 12b-32 and Regulation §229.10(d) by reference to the filings set forth below:

Exhibit No.	*Description*	*Originally Filed as Exhibit:*	*File No.*[b]	*Date Effective*
3.1	Articles of Incorporation, restated as of July 29, 1988	19.1 to the Company's September 1988 Form 10-Q Report	1-8962	11-14-88

Exhibit No.	*Description*	*Originally Filed as Exhibit:*	*File No.*[b]	*Date Effective*
3.2	Bylaws, amended as of December 15, 1999	4.1 to the Company's Registration Statement on Form S-8 No. 333-95035	1-8962	1-20-00
4.1	Mortgage and Deed of Trust Relating to APS' First Mortgage Bonds, together with forty-eight indentures supplemental thereto	4.1 to APS' September 1992 Form 10-Q Report	1-4473	11-9-92
4.2	Forty-ninth Supplemental Indenture	4.1 to APS' 1992 Form 10-K Report	1-4473	3-30-93
4.3	Fiftieth Supplemental Indenture	4.2 to APS' 1993 Form 10-K Report	1-4473	3-30-94
4.4	Fifty-first Supplemental Indenture	4.1 to APS' August 1, 1993 Form 8-K Report	1-4473	9-27-93
4.5	Fifty-second Supplemental Indenture	4.1 to APS' September 30, 1993 Form 10-Q Report	1-4473	11-15-93
4.6	Fifty-third Supplemental Indenture	4.5 to APS' Registration Statement No. 33-61228 by means of February 23, 1994 Form 8-K Report	1-4473	3-1-94
4.7	Fifty-fourth Supplemental Indenture	4.1 to APS' Registration Statements Nos. 33-61228, 33-55473, 33-64455 and 333-15379 by means of November 19, 1996 Form 8-K Report	1-4473	11-22-96
4.8	Fifty-fifth Supplemental Indenture	4.8 to APS' Registration Statement Nos. 33-55473, 33-64455 and 333-15379 by means of April 7, 1997 Form 8-K Report	1-4473	4-9-97
4.9	Agreement, dated March 21, 1994, relating to the filing of instruments defining the rights of holders of APS long-term debt not in excess of 10% of APS' total assets	4.1 to APS' 1993 Form 10-K Report	1-4473	3-30-94

Exhibit No.	*Description*	*Originally Filed as Exhibit:*	*File No.*[b]	*Date Effective*
4.10	Indenture dated as of January 1, 1995 among APS and The Bank of New York, as Trustee	4.6 to APS' Registration Statement Nos. 33-61228 and 33-55473 by means of January 1, 1995 Form 8-K Report	1-4473	1-11-95
4.11	First Supplemental Indenture dated as of January 1, 1995	4.4 to APS' Registration Statement Nos. 33-61228 and 33-55473 by means of January 1, 1995 Form 8-K Report	1-4473	1-11-95
4.12	Indenture dated as of November 15, 1996 among APS and The Bank of New York, as Trustee	4.5 to APS' Registration Statements Nos. 33-61228, 33-55473, 33-64455 and 333- 15379 by means of November 19, 1996 Form 8-K Report	1-4473	11-22-96
4.13	First Supplemental Indenture	4.6 to APS' Registration Statements Nos. 33-61228, 33-55473, 33-64455 and 333-15379 by means of November 19, 1996 Form 8-K Report	1-4473	11-22-96
4.14	Second Supplemental Indenture	4.10 to APS' Registration Statement Nos. 33-55473, 33-64455 and 333-15379 by means of April 7, 1997 Form 8-K Report	1-4473	4-9-97
4.15	Indenture dated as of December 1, 2000 between the Company and The Bank of New York, as Trustee, relating to Senior Debt Securities	4.1 to the Company's Registration Statement No. 333-53150	1-8962	1-25-01
4.16	Indenture dated as of December 1, 2000 between the Company and The Bank of New York, as Trustee, relating to subordinated Debt Securities	4.2 to the Company's Registration Statement No. 333-53150	1-8962	1-25-01

Exhibit No.	*Description*	*Originally Filed as Exhibit:*	*File No.*[b]	*Date Effective*
4.17	Specimen Certificate of Pinnacle West Capital Corporation Common Stock, no par value	4.2 to the Company's 1988 Form 10-K Report	1-8962	3-31-89
4.18	Agreement, dated March 29, 1988, relating to the filing of instruments defining the rights of holders of long-term debt not in excess of 10% of the Company's total assets	4.1 to the Company's 1987 Form 10-K Report	1-8962	3-30-88
4.19	Indenture dated as of January 15, 1998 among APS and Chase Manhattan Bank, as Trustee	4.10 to APS' Registration The Statement Nos. 333-15379 and 333-27551 by means of January 13, 1998 Form 8-K Report	1-4473	1-16-98
4.20	First Supplemental Indenture dated as of January 15, 1998	4.3 to APS' Registration Statement Nos. 333-15379 and 333-27551 by means of January 13, 1998 Form 8-K Report	1-4473	1-16-98
4.21	Second Supplemental Indenture dated as of February 15, 1999	4.3 to APS' Registration Statement Nos. 333-27551 and 333-58445 by means of February 18, 1999 Form 8-K Report	1-4473	2-22-99
4.22	Third Supplemental Indenture dated as of November 1, 1999	4.5 to APS' Registration Statement No. 333-58445 by means of November 2, 1999 Form 8-K Report	1-4473	11-5-99

Exhibit No.	*Description*	*Originally Filed as Exhibit:*	*File No.*[b]	*Date Effective*
4.23	Amended and Restated Rights Agreement, dated as of March 26, 1999, between Pinnacle West Capital Corporation and BankBoston, N.A., as Rights Agent, including (i) as Exhibit A thereto the form of Amended Certificate of Designation of Series A Participating Preferred Stock of Pinnacle West Capital Corporation, (ii) as Exhibit B thereto the form of Rights Certificate and (iii) as Exhibit C thereto the Summary of Right to Purchase Preferred Shares	4.1 to the Company's March 22, 1999 Form 8-K Report	1-8962	4-19-99
10.9	Two separate Decommissioning Trust Agreements (relating to PVNGS Units 1 and 3, respectively), each dated July 1, 1991, between APS and Mellon Bank, N.A., as Decommissioning Trustee	10.2 to APS' September 1991 Form 10-Q Report	1-4473	11-14-91
10.10	Amendment No. 1 to Decommissioning Trust Agreement (PVNGS Unit 1), dated as of December 1, 1994	10.1 to APS' 1994 Form 10- K Report	1-4473	3-30-95
10.11	Amendment No. 1 to Decommissioning Trust Agreement (PVNGS Unit 3), dated as of December 1, 1994	10.2 to APS' 1994 Form 10-K Report	1-4473	3-30-95
10.12	Amendment No. 2 to APS Decommissioning Trust Agreement (PVNGS Unit 1) dated as of July 1, 1991	10.4 to APS' 1996 Form 10-K Report	1-4473	3-28-97
10.13	Amendment No. 2 to APS Decommissioning Trust Agreement (PVNGS Unit 3) dated as of July 1, 1991	10.6 to APS' 1996 Form 10-K Report	1-4473	3-28-97

Exhibit No.	*Description*	*Originally Filed as Exhibit:*	*File No.*[b]	*Date Effective*
10.14	Amended and Restated Decommissioning Trust Agreement (PVNGS Unit 2) dated as of January 31, 1992, among APS, Mellon Bank, N.A., as Decommissioning Trustee, and State Street Bank and Trust Company, as successor to The First National Bank of Boston, as Owner Trustee under two separate Trust Agreements, each with a separate Equity Participant, and as Lessor under two separate Facility Leases, each relating to an undivided interest in PVNGS Unit 2	10.1 to the Company's 1991 Form 10-K Report	1-8962	3-26-92
10.15	First Amendment to Amended and Restated Decommissioning Trust Agreement (PVNGS Unit 2), dated as of November 1, 1992	10.2 to APS' 1992 Form 10-K Report	1-4473	3-30-93
10.16	Amendment No. 2 to Amended and Restated Decommissioning Trust Agreement (PVNGS Unit 2), dated as of November 1, 1994	10.2 to APS' 1994 Form 10-K Report	1-4473	3-30-95
10.17	Amendment No. 3 to Amended and Restated Decommissioning Trust Agreement (PVNGS Unit 2), dated as of November 1, 1994	10.1 to APS' June 1996 Form 10-Q Report	1-4473	8-9-96
10.18	Amendment No. 4 to Amended and Restated Decommissioning Trust Agreement (PVNGS Unit 2) dated as of January 31, 1992	APS 10.5 to APS' 1996 Form 10-K Report	1-4473	3-28-97

Exhibit No.	*Description*	*Originally Filed as Exhibit:*	*File No.*[b]	*Date Effective*
10.19	Asset Purchase and Power Exchange Agreement dated September 21, 1990 between APS and PacifiCorp, as amended as of October 11, 1990 and as of July 18, 1991	10.1 to APS' June 1991 Form 10-Q Report	1-4473	8-8-91
10.20	Long-Term Power Transaction Agreement dated September 21, 1990 between APS and PacifiCorp, as amended as of October 11, 1990, and as of July 8, 1991	10.2 to APS' June 1991 Form 10-Q Report	1-4473	8-8-91
10.21	Amendment No. 1 dated April 5, 1995 to the Long-Term Power Transaction Agreement and Asset Purchase and Power Exchange Agreement between PacifiCorp and APS	10.3 to APS' 1995 Form 10-K Report	1-4473	3-29-96
10.22	Restated Transmission Agreement between PacifiCorp and APS dated April 5, 1995	10.4 to APS' 1995 Form 10-K Report	1-4473	3-29-96
10.23	Contract among PacifiCorp, APS and United States Department of Energy Western Area Power Administration, Salt Lake Area Integrated Projects for Firm Transmission Service dated May 5, 1995	10.5 to APS' 1995 Form 10-K Report	1-4473	3-29-96
10.24	Reciprocal Transmission Service Agreement between APS and PacifiCorp dated as of March 2, 1994	10.6 to APS' 1995 Form 10-K Report	1-4473	3-29-96

Exhibit No.	*Description*	*Originally Filed as Exhibit:*	*File No.*[b]	*Date Effective*
10.25	Contract, dated July 21, 1984, with DOE providing for the disposal of nuclear fuel and/or high -level radioactive waste, ANPP	10.31 to the Company's Form S-14 Registration Statement	2-96386	3-13-85
10.26	Indenture of Lease with Navajo Tribe of Indians, Four Corners Plant	5.01 to APS' Form S-7 Registration Statement	2-59644	9-1-77
10.27	Supplemental and Additional Indenture of Lease, including amendments and supplements to original lease with Navajo Tribe of Indians, Four Corners Plant	5.02 to APS' Form S-7 Registration Statement	2-59644	9-1-77
10.28	Amendment and Supplement No. 1 to Supplemental and Additional Indenture of Lease Four Corners, dated April 25, 1985	10.36 to the Company's Registration Statement on Form 8-B Report	1-8962	7-25-85
10.29	Application and Grant of multi-party rights-of-way and easements, Four Corners Plant Site	5.04 to APS' Form S-7 Registration Statement	2-59644	9-1-77
10.30	Application and Amendment No. 1 to Grant of multi-party rights-of-way and easements, Four Corners Power Plant Site dated April 25, 1985	10.37 to the Company's Registration Statement on Form 8-B	1-8962	7-25-85
10.31	Application and Grant of Arizona Public Service Company rights- of-way and easements, Four Corners Plant Site	5.05 to APS' Form S-7 Registration Statement	2-59644	9-1-77
10.32	Application and Amendment No. 1 to Grant of Arizona Public Service Company rights-of-way and easements, Four Corners Power Plant Site dated April 25, 1985	10.38 to the Company's Registration Statement on Form 8-B	1-8962	7-25-85

Exhibit No.	*Description*	*Originally Filed as Exhibit:*	*File No.*[b]	*Date Effective*
10.33	Indenture of Lease, Navajo Units 1, 2, and 3	5(g) to APS' Form S-7 Registration Statement	2-36505	3-23-70
10.34	Application of Grant of rights-of-way and easements, Navajo Plant	5(h) to APS Form S-7 Registration Statement	2-36505	3-23-70
10.35	Water Service Contract Assignment with the United States Department of Interior, Bureau of Reclamation, Navajo Plant	5(l) to APS' Form S-7 Registration Statement	2-394442	3-16-71
10.36	Arizona Nuclear Power Project Participation Agreement, dated August 23, 1973, among APS Salt River Project Agricultural Improvement and Power District, Southern California Edison Company, Public Service Company of New Mexico, El Paso Electric Company, Southern California Public Power Authority, and Department of Water and Power of the City of Los Angeles, and amendments 1-12 thereto	10. 1 to APS' 1988 Form 10-K	1-4473	3-8-89

Exhibit No.	*Description*	*Originally Filed as Exhibit:*	*File No.*[b]	*Date Effective*
10.37	Amendment No. 13, dated as of April 22, 1991, to Arizona Nuclear Power Project Participation Agreement, dated August 23, 1973, among APS, Salt River Project Agricultural Improvement and Power District, Southern California Edison Company, Public Service Company of New Mexico, El Paso Electric Company, Southern California Public Power Authority, and Department of Water and Power of the City of Los Angeles	10.1 to APS' March 1991 Form 10-Q	1-4473	5-15-91
10.38	Amendment No. 14 to Arizona Nuclear Power Project Participation Agreement, dated August 23, 1973, among APS, Salt River Project Agricultural Improvement and Power District, Southern California Edison Company, Public Service Company of New Mexico, El Paso Electric Company, Southern California Public Power Authority, and Department of Water and Power of the City of Los Angeles	99.1 to the Company's June 2000 Form 10-Q Report	1-8962	8-14-00
10.39[c]	Facility Lease, dated as of August 1, 1986, between State Street Bank and Trust Company, as successor to The First National Bank of Boston, in its capacity as Owner Trustee, as Lessor, and APS, as Lessee	4.3 to APS' Form S-3 Registration Statement	33-9480	10-24-86

Exhibit No.	*Description*	*Originally Filed as Exhibit:*	*File No.*[b]	*Date Effective*
10.40[c]	Amendment No. 1, dated as of November 1, 1986, to Facility Lease, dated as of August 1, 1986, between State Street Bank and Trust Company, as successor to The First National Bank of Boston, in its capacity as Owner Trustee, as Lessor, and APS, as Lessee	10.5 to APS' September 1986 Form 10-Q Report by means of Amendment No. on December 3, 1986 Form 8	1-4473	12-4-86
10.41 [c]	Amendment No. 2 dated as of June 1, 1987 to Facility Lease dated as of August 1, 1986 between State Street Bank and Trust Company, as successor to The First National Bank of Boston, as Lessor, and APS, as Lessee	10.3 to APS' 1988 Form 10-K Report	1-4473	3-8-89
10.42 [c]	Amendment No. 3, dated as of March 17, 1993, to Facility Lease, dated as of August 1, 1986, between State Street Bank and Trust Company, as successor to The First National Bank of Boston, as Lessor, and APS, as Lessee	10.3 to APS' 1992 Form 10-K Report	1-4473	3-30-93
10.43	Facility Lease, dated as of December 15, 1986, between State Street Bank and Trust Company, as successor to The First National Bank of Boston, in its capacity as Owner Trustee, as Lessor, and APS, as Lessee	10.1 to APS' November 18 1986 Form 8-K Report	1-4473	1-20-87

Exhibit No.	*Description*	*Originally Filed as Exhibit:*	*File No.*[b]	*Date Effective*
10.44	Amendment No. 1, dated as of August 1, 1987, to Facility Lease, dated as of December 15, 1986, between State Street Bank and Trust Company, as successor to The First National Bank of Boston, as Lessor, and APS, as Lessee	4.13 to APS' Form S-3 Registration Statement No. 33-9480 by means of August 1, 1987 Form 8-K Report	1-4473	8-24-87
10.45	Amendment No. 2, dated as of March 17, 1993, to Facility Lease, dated as of December 15, 1986, between State Street Bank and Trust Company, as successor to The First National Bank of Boston, as Lessor, and APS, as Lessee	10.4 to APS' 1992 Form 10-K Report	1-4473	3-30-93
10.46[a]	Pinnacle West Capital Corporation Supplemental Excess Benefit Retirement Plan, as amended and restated, dated December 7, 1999	10.13 to the Company's 1999 Form 10-K Report	1-8962	3-30-00
10.47[a]	Trust for the Pinnacle West Capital Corporation, Arizona Public Service Company and SunCor Development Company Deferred Compensation Plans dated August 1, 1996	10.14 to the Company's 1999 Form 10-K Report	1-8962	3-30-00
10.48[a]	First Amendment dated December 7, 1999 to the Trust for the Pinnacle West Capital Corporation, Arizona Public Service Company and SunCor Development Company Deferred Compensation Plans	10.15 to the Company's 1999 Form 10-K Report	1-8962	3-30-00

Exhibit No.	*Description*	*Originally Filed as Exhibit:*	*File No.*[b]	*Date Effective*
10.49[a]	Directors' Deferred Compensation Plan, as restated, effective January 1, 1986	10.1 to APS' June 1986 Form 10-Q Report	1-4473	8-13-86
10.50 [a]	Second Amendment to the Arizona Public Service Company Deferred Compensation Plan, effective as of January 1, 1993	10.2 to APS' 1993 Form 10-K Report	1-4473	3-30-94
10.51 [a]	Third Amendment to the Arizona Public Service Company Directors' Deferred Compensation Plan, effective as of May 1, 1993	10.1 to APS' September 1994 Form 10-Q	1-4473	11-10-94
10.52 [a]	Fourth Amendment dated December 28, 1999 to the Arizona Public Service Company Directors Deferred Compensation Plan	10.8 to the Company's 1999 Form 10-K Report	1-8962	3-30-00
10.53[a]	Arizona Public Service Company Deferred Compensation Plan, as restated, effective January 1, 1984, and the second and third amendments thereto, dated December 22, 1986, and December 23, 1987 respectively	10.4 to APS' 1988 Form 10-K Report	1-4473	3-8-89
10.54[a]	Third Amendment to the Arizona Public Service Company Deferred Compensation Plan, effective as of January 1, 1993	10.3 to APS' 1993 Form 10-K Report	1-4473	3-30-94
10.55[a]	Fourth Amendment to the Arizona Public Service Company Deferred Compensation Plan effective as of May 1, 1993	10.2 to APS' September 1994 Form 10-Q Report	1-4473	11-10-94

Exhibit No.	*Description*	*Originally Filed as Exhibit:*	*File No.*[b]	*Date Effective*
10.56[a]	Fifth Amendment to the Arizona Public Service Company Deferred Compensation Plan	10.3 to APS' 1996 Form 10-K Report	1-4473	3-28-97
10.57[a]	First Amendment effective as of January 1, 1999, to the Pinnacle West Capital Corporation, Arizona Public Service Company, SunCor Development Company and El Dorado Investment Company Deferred Compensation Plan	10.7 to the Company's 1999 Form 10-K Report	1-8962	3-30-00
10.58[a]	Second Amendment effective January 1, 2000 to the Pinnacle West Capital Corporation, Arizona Public Service Company, SunCor Development Company and El Dorado Investment Company Deferred Compensation Plan	10.10 to the Company's 1999 Form 10-K Report	1-8962	3-30-00
10.59[a]	Pinnacle West Capital Corporation, Arizona Public Service Company, SunCor Development Company and El Dorado Investment Company Deferred Compensation Plan as amended and restated effective January 1, 1996	10.10 to APS' 1995 Form 10-K Report	1-4473	3-29-96
10.60[a]	Pinnacle West Capital Corporation and Arizona Public Service Company Directors' Retirement Plan, effective as of January 1, 1995	10.7 to APS' 1994 Form 10-K Report	1-4473	3-30-95
10.61[a]	Letter Agreement dated July 28, 1995 between Arizona Public Service Company and Armando B. Flores	10.16 to the Company's 1999 Form 10-K Report	1-8962	3-30-00

Exhibit No.	*Description*	*Originally Filed as Exhibit:*	*File No.*[b]	*Date Effective*
10.62[a]	Letter Agreement dated October 3, 1997 between Arizona Public Service Company and James M. Levine	10.17 to the Company's 1999 Form 10-K Report	1-8962	3-30-00
10.63[a]	Letter Agreement dated as of January 1, 1996 between APS and Robert G. Matlock & Associates, Inc. for consulting services	10.8 to APS' 1995 Form 10-K Report	1-4473	3-29-96
10.64[a]	Letter Agreement dated December 21, 1993, between APS and William L. Stewart	10.7 to APS' 1994 Form 10-K Report	1-4473	3-30-96
10.65[a]	Letter Agreement dated August 16, 1996 between APS and William L. Stewart	10.8 to APS' 1996 Form 10-K Report	1-4473	3-28-97
10.66[a]	Letter Agreement between APS and William L. Stewart	10.2 to APS' September 1997 Form 10-Q Report	1-4473	11-12-97
10.67[a]	Letter Agreement dated December 13, 1999 between APS and William L. Stewart			
10.68[ad]	Key Executive Employment and Severance Agreement between Pinnacle West and certain executive officers of Pinnacle West and its subsidiaries	10.1 to June 1999 Form 10-Q Report	1-8962	8-16-99
10.69[a]	Pinnacle West Capital Corporation Stock Option and Incentive Plan	10.1 to APS' 1992 Form 10-K Report	1-4473	3-30-93
10.70[a]	First Amendment dated December 7, 1999 to the Pinnacle West Capital Corporation Stock Option and Incentive Plan	10.11 to the Company's 1999 Form 10-K Report	1-8962	3-30-00

Exhibit No.	*Description*	*Originally Filed as Exhibit:*	*File No.*[b]	*Date Effective*
10.71[a]	Pinnacle West Capital Corporation 1994 Long-Term Incentive Plan, effective as of March 23, 1994	A to the Proxy Statement for the Plan Report for the Company's 1994 Annual Meeting of Shareholders	1-8962	4-16-94
10.72[a]	First Amendment dated December 7, 1999 to the Pinnacle West Capital Corporation 1994 Long-Term Incentive Plan	10.12 to the Company's 1999 Form 10-K Report	1-8962	3-30-00
10.73[a]	Pinnacle West Capital Corporation Director Equity Participation Plan	B to the Proxy Statement for the Plan Report for the Company's 1994 Annual Meeting of Shareholders	1-8962	4-16-94
10.74[a]	Pinnacle West Capital Corporation 2000 Director Equity Plan	99.1 to the Company's Registration Statement on Form S-8 (No. 333-40796)	1-8962	7-3-00
10.75[a]	Pinnacle West Capital Corporation and Arizona Public Service Company Directors' Retirement Plan, as amended and restated on June 21, 2000	99.2 to the Company's Registration Statement on Form S-8 (No. 333-40796)	1-8962	7-3-00
10.76	Agreement No. 13904 (Option and Purchase of Effluent) with Cities of Phoenix, Glendale, Mesa, Scottsdale, Tempe, Town of Youngtown, and Salt River Project Agricultural Improvement and Power District, dated April 23, 1973	10.3 to APS' 1991 Form 10-K Report	1-4473	3-19-92

Exhibit No.	*Description*	*Originally Filed as Exhibit:*	*File No.*[b]	*Date Effective*
10.77	Agreement for the Sale and purchase of Wastewater Effluent with City of Tolleson and Salt River Agricultural Improvement and Power District, dated June 12, 1981, including Amendment No. 1 dated as of November 12, 1981 and Amendment No. 2 dated as of June 4, 1986	10.4 to APS' 1991 Form 10-K Report	1-4473	3-19-92
10.78[a]	APS Director Equity Plan	10.1 to September 1997 Form 10-Q Report	1-4473	11-12-97
10.79	Territorial Agreement between the Company and Salt River Project	10.1 to APS' March 1998 Form 10-Q Report	1-4473	5-15-98
10.80	Power Coordination Agreement between the Company and Salt River Project	10.2 to APS' March 1998 Form 10-Q Report	1-4473	5-15-98
10.81	Memorandum of Agreement between the Company and Salt River Project	10.3 to APS' March 1998 Form 10-Q Report	1-4473	5-15-98
10.82	Addendum to Memorandum of Agreement between APS and Salt River Project dated as of May 19, 1998	10.2 to APS' May 19, 1998 Form 8-K Report	1-4473	6-26-98
99.1	Collateral Trust Indenture among PVNGS II Funding Corp., Inc., APS and Chemical Bank, as Trustee	4.2 to APS' 1992 Form 10 K Report	1-4473	3-30-93
99.2	Supplemental Indenture to Collateral Trust Indenture among PVNGS II Funding Corp., Inc., APS and Chemical Bank, as Trustee	4.3 to APS' 1992 Form 10 K Report	1-4473	3-30-93

Exhibit No.	*Description*	*Originally Filed as Exhibit:*	*File No.*[b]	*Date Effective*
99.3[c]	Participation Agreement, dated as of August 1, 1986, among PVNGS Funding Corp., Inc., Bank of America National Trust and Savings Association, State Street Bank and Trust Company, as successor to The First National Bank of Boston, in its individual capacity and as Owner Trustee, Chemical Bank, in its individual capacity and as Indenture Trustee, APS, and the Equity Participant named therein	28.1 to APS' September 1992 Form 10-Q Report	1-4473	11-9-92
99.4[c]	Amendment No. 1 dated as of November 1, 1986, to Participation Agreement, dated as of August 1, 1986, among PVNGS Funding Corp., Inc., Bank of America National Trust and Savings Association, State Street Bank and Trust Company, as successor to The First National Bank of Boston, in its individual capacity and as Owner Trustee, Chemical Bank, in its individual capacity and as Indenture Trustee, APS, and the Equity Participant named therein	10.8 to APS' September 1986 Form 10-Q Report by means of Amendment No. 1, on December 3, 1986 Form 8	1-4473	12-4-86

Exhibit No.	*Description*	*Originally Filed as Exhibit:*	*File No.*[b]	*Date Effective*
99.5[c]	Amendment No. 2, dated as of March 17, 1993, to Participation Agreement, dated as of August 1, 1986, among PVNGS Funding Corp., Inc., PVNGS II Funding Corp., Inc., State Street Bank and Trust Company, as successor to The First National Bank of Boston, in its individual capacity and as Owner Trustee, Chemical Bank, in its individual capacity and as Indenture Trustee, APS, and the Equity Participant named therein	28.4 to APS' 1992 Form 10-K Report	1-4473	3-30-93
99.6[c]	Trust Indenture, Mortgage, Security Agreement and Assignment of Facility Lease, dated as of August 1, 1986, between State Street Bank and Trust Company, as successor to The First National Bank of Boston, as Owner Trustee, and Chemical Bank, as Indenture Trustee	4.5 to APS' Form S-3 Registration Statement	33-9480	10-24-86
99.7[c]	Supplemental Indenture No. 1, dated as of November 1, 1986 to Trust Indenture, Mortgage, Security Agreement and Assignment of Facility Lease, dated as of August 1, 1986, between State Street Bank and Trust Company, as successor to The First National Bank of Boston, as Owner Trustee, and Chemical Bank, as Indenture Trustee	10.6 to APS' September 1986 Form 10-Q Report by means of Amendment No. 1 on December 3, 1986 Form 8	1-4473	12-4-86

Exhibit No.	*Description*	*Originally Filed as Exhibit:*	*File No.*[b]	*Date Effective*
99.8[c]	Supplemental Indenture No. 2 to Trust Indenture, Mortgage, Security Agreement and Assignment of Facility Lease, dated as of August 1, 1986, between State Street Bank and Trust Company, as successor to The First National Bank of Boston, as Owner Trustee, and Chemical Bank, as Lease Indenture Trustee	28.14 to APS' 1992 Form 10-K Report	1-4473	3-30-93
99.9[c]	Assignment, Assumption and Further Agreement, dated as of August 1, 1986, between APS and State Street Bank and Trust Company, as successor to The First National Bank of Boston, as Owner Trustee	28.3 to APS' Form S-3 Registration Statement	33-9480	10-24-86
99.10[c]	Amendment No. 1, dated as of November 1, 1986, to Assignment, Assumption and Further Agreement, dated as of August 1, 1986, between APS and State Street Bank and Trust Company, as successor to The First National Bank of Boston, as Owner Trustee	10.10 to APS' September 1986 Form 10-Q Report by means of Amendment No. 1 on December 3, 1986 Form 8	1-4473	12-4-86
99.11[c]	Amendment No. 2, dated as of March 17, 1993, to Assignment, Assumption and Further Agreement, dated as of August 1, 1986, between APS and State Street Bank and Trust Company, as successor to The First National Bank of Boston, as Owner Trustee	28.6 to APS' 1992 Form 10-K Report	1-4473	3-30-93

Exhibit No.	*Description*	*Originally Filed as Exhibit:*	*File No.*[b]	*Date Effective*
99.12	Participation Agreement, dated as of December 15, 1986, among PVNGS Funding Report Corp., Inc., State Street Bank and Trust Company, as successor to The First National Bank of Boston, in its individual capacity and as Owner Trustee, Chemical Bank, in its individual capacity and as Indenture Trustee under a Trust Indenture, APS, and the Owner Participant named therein	28.2 to APS' September 1992 Form 10-Q Report	1-4473	11-9-92
99.13	Amendment No. 1, dated as of August 1, 1987, to Participation Agreement, dated as of December 15, 1986, among PVNGS Funding Corp., Inc. as Funding Corporation, State Street Bank and Trust Company, as successor to The First National Bank of Boston, as Owner Trustee, Chemical Bank, as Indenture Trustee, APS, and the Owner Participant named therein	28.20 to APS' Form S-3 Registration Statement No. 33-9480 by means of a November 6, 1986 Form 8-K Report	1-4473	8-10-87

Exhibit No.	*Description*	*Originally Filed as Exhibit:*	*File No.*[b]	*Date Effective*
99.14	Amendment No. 2, dated as of March 17, 1993, to Participation Agreement, dated as of December 15, 1986, among PVNGS Funding Corp., Inc., PVNGS II Funding Corp., Inc., State Street Bank and Trust Company, as successor to The First National Bank of Boston, in its individual capacity and as Owner Trustee, Chemical Bank, in its individual capacity and as Indenture Trustee, APS, and the Owner Participant named therein	28.5 to APS' 1992 Form 10-K Report	1-4473	3-30-93
99.15	Trust Indenture, Mortgage Security Agreement and Assignment of Facility Lease, dated as of December 15, 1986, between State Street Bank and Trust Company, as successor to The First National Bank of Boston, as Owner Trustee, and Chemical Bank, as Indenture Trustee	10.2 to APS' November 18, 1986 Form 10-K Report	1-4473	1-20-87
99.16	Supplemental Indenture No. 1, dated as of August 1, 1987, to Trust Indenture, Mortgage, Security Agreement and Assignment of Facility Lease, dated as of December 15, 1986, between State Street Bank and Trust Company, as successor to The First National Bank of Boston, as Owner Trustee, and Chemical Bank, as Indenture Trustee	4.13 to APS' Form S-3 Registration Statement No. 33-9480 by means of August 1, 1987 Form 8-K Report	1-4473	8-24-87

Exhibit No.	*Description*	*Originally Filed as Exhibit:*	*File No.*[b]	*Date Effective*
99.17	Supplemental Indenture No. 2 to Trust Indenture Mortgage, Security Agreement and Assignment of Facility Lease, dated as of December 15, 1986, between State Street Bank and Trust Company, as successor to The First National Bank of Boston, as Owner Trustee, and Chemical Bank, as Lease Indenture Trustee	4.5 to APS' 1992 Form 10-K Report	1-4473	3-30-93
99.18	Assignment, Assumption and Further Agreement, dated as of December 15, 1986, between APS and State Street Bank and Trust Company, as successor to The First National Bank of Boston, as Owner Trustee	10.5 to APS' November 18, 1986 Form 8-K Report	1-4473	1-20-87
99.19	Amendment No. 1, dated as of March 17, 1993, to Assignment, Assumption and Further Agreement, dated as of December 15, 1986, between APS and State Street Bank and Trust Company, as successor to The First National Bank of Boston, as Owner Trustee	28.7 to APS' 1992 Form 10-K Report	1-4473	3-30-93
99.20[c]	Indemnity Agreement dated as of March 17, 1993 by APS	28.3 to APS' 1992 Form 10-K Report	1-4473	3-30-93
99.21	Extension Letter, dated as of August 13, 1987, from the signatories of the Participation Agreement to Chemical Bank	28.20 to APS' Form S-3 Registration Statement No. 33-9480 by means of a November 6, 1986 Form 8-K Report	1-4473	8-10-87
99.22	Arizona Corporation Commission Order dated December 6, 1991	28.1 to APS' 1991 Form 10-K Report	1-4473	3-19-92

Exhibit No.	*Description*	*Originally Filed as Exhibit:*	*File No.*[b]	*Date Effective*
99.23	Arizona Corporation Commission Order dated June 1, 1994	10.1 to APS' June 1994 form 10-Q Report	1-4473	8-12-94
99.24	Rate Reduction Agreement dated December 4, 1995 between APS and the ACC Staff	10.1 to APS' December 4, 1995 8-K Report	1-4473	12-14-95
99.25	ACC Order dated April 24, 1996	10.1 to APS' March 1996 Form 10-Q Report	1-4473	5-14-96
99.26	Arizona Corporation Commission Order, Decision No. 59943, dated December 26, 1996, including the Rules regarding the introduction of retail competition in Arizona	99.1 to APS' 1996 Form 10-K Report	1-4473	3-28-97
99.27	Retail Electric Competition Rules	10.1 to APS' June 1998 Form 10-Q Report	1-4473	8-14-98
99.28	Arizona Corporation Commission Order, Decision No. 61973, dated October 6, 1999, approving APS' Settlement Agreement	10.1 to APS' September 1999 10-Q Report	1-4473	11-15-99
99.29	Addendum to Settlement Agreement	10.1 to the Company's September 2000 Form 10-Q Report	1-8962	11-14-00
99.29	Arizona Corporation Commission Order, Decision No. 61969, dated September 29, 1999, including the Retail Electric Competition Rules	10.2 to APS' September 1999 10-Q Report	1-4473	11-15-99
99.30	Purchase and Sale Agreement for Palo Verde Nuclear Generating Station by and between Southern California Edison Company and Pinnacle West Energy Corporation, dated as of April 27, 2000	99.1 to the Company's March 2000 Form 10-Q Report	1-8962	5-15-00

Exhibit No.	*Description*	*Originally Filed as Exhibit:*	*File No.*[b]	*Date Effective*
99.31	Purchase and Sale Agreement for Four Corners Power Plant by and between Southern California Edison Company and Pinnacle West Energy Corporation, dated as of April 27, 2000	99.2 to the Company's March 2000 10-Q Report	1-8962	5-15-00

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[a]Management contract or compensatory plan or arrangement to be filed as an exhibit pursuant to Item 14(c) of Form 10-K.

[b]Reports filed under File No. 1-4473 and 1-8962 were filed in the office of the Securities and Exchange Commission located in Washington, D.C.

[c]An additional document, substantially identical in all material respects to this Exhibit, has been entered into, relating to an additional Equity Participant. Although such additional document may differ in other respects (such as dollar amounts, percentages, tax indemnity matters, and dates of execution), there are no material details in which such document differs from this Exhibit.

[d]Additional agreements, substantially identical in all material respects to this Exhibit have been entered into with additional persons. Although such additional documents may differ in other respects (such as dollar amounts and dates of execution), there are no material details in which such agreements differ from this Exhibit.

Reports on Form 8-K

During the quarter ended December 31, 2000, and the period ended March 13, 2001, the Company filed the following Reports on Form 8-K:

Report dated October 26, 2000, regarding the written materials presented at an analyst conference in Phoenix, Arizona.

Report dated November 27, 2000, regarding: (i) the Court of Appeals affirming the ACC's approval of the 1999 Settlement Agreement; a Maricopa County Superior Court judge's final judgment related to the Rules; the proposed timing of the transfer of generation assets; and issues related to generation expansion.

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the Registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized.

PINNACLE WEST CAPITAL CORPORATION
(Registrant)

Date: March 13, 2001

/s/William J. Post
(William J. Post, Chairman of the Board of Directors and Chief Executive Officer)

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the registrant and in the capacities and on the dates indicated.

Signature	***Title***	***Date***
/s/William J. Post (William J. Post, Chairman of the Board of Directors and Chief Executive Officer)	Principal Executive Officer and Director	March 13, 2001
/s/Jack E. Davis (Jack E. Davis, President)	President and Director	March 13, 2001
/s/Michael V. Palmeri (Michael V. Palmeri, Vice President, Finance)	Principal Financial Officer	March 13, 2001
/s/Chris N. Froggatt (Chris N. Froggatt, Vice President and Controller)	Principal Accounting Officer	March 13, 2001
/s/Edward N. Basha, Jr. (Edward N. Basha, Jr.)	Director	March 13, 2001

/s/Michael L. Gallagher (Michael L. Gallagher)	Director	March 13, 2001
/s/Pamela Grant (Pamela Grant)	Director	March 13, 2001
/s/Roy A. Herberger, Jr. (Roy A. Herberger, Jr.)	Director	March 13, 2001
/s/Martha O. Hesse (Martha O. Hesse)	Director	March 13, 2001
/s/William S. Jamieson, Jr. (William S. Jamieson, Jr.)	Director	March 13, 2001
/s/Humberto S. Lopez (Humberto S. Lopez)	Director	March 13, 2001
/s/Robert G. Matlock (Robert G. Matlock)	Director	March 13, 2001
/s/Kathryn L. Munro (Kathryn L. Munro)	Director	March 13, 2001
/s/Bruce J. Nordstrom (Bruce J. Nordstrom)	Director	March 13, 2001

C

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Company: PINNACLE WEST CAPITAL CORP
Form Type: U-3A-2 SEC File #: 069-00306
Description: FORM U-3A-2 OF PINNACLE WEST CAPITAL CORPORATION
SEC File Date: 02/28/01

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Adopted November 9, 1939 File No. 69-306

SECURITIES AND EXCHANGE COMMISSION
Washington, D.C.

FORM U-3A-2

STATEMENT BY HOLDING COMPANY
CLAIMING EXEMPTION UNDER RULE U-3A-2
FROM THE PROVISIONS OF THE
PUBLIC UTILITY HOLDING COMPANY ACT OF 1935

To Be Filed Annually Prior to March 1

Pinnacle West Capital Corporation

(Name of Company)

hereby files with the Securities and Exchange Commission, pursuant to Rule 2, its statement claiming exemption as a holding company from the provisions of the Public Utility Holding Company Act of 1935, and submits the following information:

1. NAME, STATE OF ORGANIZATION, LOCATION AND NATURE OF BUSINESS OF CLAIMANT AND EVERY SUBSIDIARY THEREOF, OTHER THAN ANY EXEMPT WHOLESALE GENERATOR (EWG) OR FOREIGN UTILITY COMPANY IN WHICH CLAIMANT DIRECTLY OR INDIRECTLY HOLDS AN INTEREST.

Pinnacle West Capital Corporation ("Claimant"), having been incorporated on February 20, 1985 under the laws of the State of Arizona, and having its principal executive offices at 400 East Van Buren, Suite 700, Phoenix, Arizona 85004, was organized principally to acquire and hold securities of other corporations for investment purposes. The following are the subsidiaries of the Claimant:

a. Arizona Public Service Company ("APS" or the "Company"), is engaged principally in serving electricity in the State of Arizona. Incorporated in 1920 under the laws of the State of Arizona and having its principal executive offices at 400 North Fifth Street, Phoenix, Arizona 85004, APS became a subsidiary of the Claimant pursuant to a corporate restructuring plan approved by the Company's shareholders on April 18, 1985.

(1) AXIOM Power Solutions, Inc. ("AXIOM") -- an Arizona corporation having been incorporated on October 29, 1996 and having its principal executive offices at 400 E. Van Buren, Phoenix, Arizona 85004, was organized primarily to sell security and energy management products and services. AXIOM is a wholly-owned subsidiary of APS.

(2) Bixco, Inc. ("Bixco") -- an Arizona corporation having been incorporated on June 4, 1971 and having its principal executive offices at 400 North Fifth Street, Phoenix, Arizona 85004, was organized primarily to conduct exploration activities for energy resources and other valuable minerals. Subsequent to the sale of its oil and natural gas properties in 1981, Bixco has been inactive. Bixco is a wholly-owned subsidiary of APS.

b. APS Energy Services Company, Inc. ("APSES") -- an Arizona corporation having been incorporated on November 6, 1998 and having its principal executive offices at 400 E. Van Buren, Phoenix, Arizona 85004, was organized primarily to sell energy, products and services. APSES is a wholly-owned subsidiary of the Claimant.

c. SunCor Development Company ("SunCor") - an Arizona corporation having been incorporated on June 30, 1965 and having its principal executive offices at 3838 North Central Avenue, Suite 1500,

Phoenix, Arizona 85012, is a wholly-owned subsidiary of Claimant engaged primarily in the owning, holding and development of real property.

(1) SunCor Golf, Inc. ("SunCor Golf") (previously named "SunCor Resort & Golf Management, Inc." and "SunCor Farms, Inc.") -- an Arizona corporation having been incorporated on December 31, 1986 and having its principal executive offices at 3838 North Central Avenue, Suite 1500, Phoenix, Arizona 85012, operates and manages golf, food and beverage for the Coral Canyon Golf Course, Sedona Golf Resort, SunRidge Canyon Golf Club, Sanctuary Golf Club at West World and Palm Valley Golf Club. SunCor Golf is a wholly-owned subsidiary of SunCor.

(2) Litchfield Park Service Company ("LPSCO") -- an Arizona corporation having been incorporated on September 21, 1954 and having its principal executive offices at 111 West Wigwam Boulevard, Suite B, Litchfield Park, Arizona 85340, is a regulated public utility engaged in providing water and sewer services to commercial and residential customers. LPSCO became a wholly-owned subsidiary of SunCor on December 31,1986.

(3) Golden Heritage Homes, Inc. ("Golden Heritage Homes") -- (previously named "SunCor Homes, Inc.", "LGR, Inc." and "WGP Realty, Inc.") an Arizona corporation having been incorporated on May 14, 1986 and having its principal executive offices at 7025 East Greenway Parkway, Suite 100, Scottsdale, Arizona 85254, builds and sells single family residential real property. Golden Heritage Homes is a wholly-owned subsidiary of SunCor.

(4) Golden Heritage Construction, Inc. ("GH Construction") -- an Arizona corporation having been incorporated on December 30, 1993 and having its principal executive offices at 3838 North Central Avenue, Suite 1500, Phoenix, Arizona 85012, was organized to serve as a general residential contractor. GH Construction became a wholly-owned subsidiary of Golden Heritage Homes, Inc. on January 1, 1996.

(5) SCM, Inc. ("SCM") -- an Arizona corporation having been incorporated on May 14, 1991 and having its principal executive offices at 3838 North Central Avenue, Suite 1500, Phoenix, Arizona 85012, was organized to participate in real

estate joint ventures and other real estate related activities. SCM is a wholly-owned subsidiary of SunCor.

(6) Golf de Mexico, S.A. DE C.V. ("Golf de Mexico") -- a Mexican variable capital corporation having been incorporated on February 8, 1992 in Tijuana, Baja California, Mexico, and having its principal executive offices at 3838 North Central Avenue, Suite 1500, Phoenix, Arizona 85012, was organized to operate and manage the Real del Mar Golf Course in Mexico. Golf de Mexico has been inactive since 1997.

(7) SunCor Realty & Management Company ("SunCor Realty") -- (previously named Russell Ranch Development Company) an Arizona corporation having been incorporated on April 1, 1994 and having its principal executive offices at 3838 North Central Avenue, Suite 1500, Phoenix, Arizona 85012 was organized to participate in real estate management and other real estate related activities. SunCor Realty is a wholly-owned subsidiary of SunCor.

(8) Palm Valley Golf Club, Inc. ("Palm Valley Golf") -- an Arizona corporation having been incorporated on January 23, 1996 and having its principal executive offices at 3838 North Central Avenue, Suite 1500, Phoenix, Arizona 85012, was organized to hold title to the Palm Valley Golf Course. Palm Valley Golf is a wholly-owned subsidiary of SunCor.

(9) Rancho Viejo de Santa Fe, Inc. ("Rancho Viejo") -- a New Mexico corporation having been incorporated on March 18, 1996 and having its principal executive offices at 1590-B Pacheco Street, Santa Fe, New Mexico 87505, was organized to engage in real estate development in New Mexico. Rancho Viego is a wholly-owned subsidiary of SunCor.

(10) Ranchland Utility Company ("Ranchland") -- a New Mexico corporation having been incorporated on September 5, 1997 and having its principal executive offices at 1590-B Pacheco Street, Santa Fe, New Mexico 87505 is a waste water utility. Ranchland is a wholly-owned subsidiary of Rancho Viejo.

d. El Dorado Investment Company -- an Arizona corporation having been incorporated on July 27, 1983 and having its principal executive offices at 400 East Van Buren, Suite 800, Phoenix, Arizona 85004, is a

wholly-owned subsidiary of Claimant engaged primarily in the acquisition and holding of stocks and securities of other companies for investment purposes.

e. Pinnacle West Energy Corporation ("PWEC") - an Arizona corporation having been incorporated on September 27, 1999, and having its principal executive offices at 400 North Fifth Street, Phoenix, Arizona 85004, was organized primarily for the development, production and sale of wholesale energy. PWEC is a wholly-owned subsidiary of the Claimant.

2. A BRIEF DESCRIPTION OF THE PROPERTIES OF CLAIMANT AND EACH OF ITS SUBSIDIARY PUBLIC UTILITY COMPANIES USED FOR THE GENERATION, TRANSMISSION AND DISTRIBUTION OF ELECTRIC ENERGY FOR SALE, OR FOR THE PRODUCTION, TRANSMISSION AND DISTRIBUTION OF NATURAL OR MANUFACTURED GAS, INDICATING THE LOCATION OF PRINCIPAL GENERATING PLANTS, TRANSMISSION LINES, PRODUCING FIELDS, GAS MANUFACTURING PLANTS AND ELECTRIC AND GAS DISTRIBUTION FACILITIES, INCLUDING ALL SUCH PROPERTIES WHICH ARE OUTSIDE THE STATE IN WHICH CLAIMANT AND ITS SUBSIDIARIES ARE ORGANIZED AND ALL TRANSMISSION OR PIPELINES WHICH DELIVER OR RECEIVE ELECTRIC ENERGY OR GAS AT THE BORDERS OF SUCH STATE.

Neither the Claimant nor any of its subsidiaries own property used for the production, transmission and distribution of natural or manufactured gas. APS, a "public utility company" as that term is defined in the Public Utility Holding Company Act of 1935, is the only one of Claimant's subsidiaries that owns property used for the generation, transmission and distribution of electric energy for sale.

Exhibit D attached hereto shows the location of APS' major generating plants (including those owned jointly with others), principal transmission lines (including those operated for others) and interconnections of transmission lines with out-of-state utilities at state lines. All of such facilities, except the Four Corners Generating Station ("Four Corners"), and all of APS' distribution facilities, are located within the State of Arizona. Four Corners is a mine-mouth power plant, located in the northwest corner of New Mexico, near the city of Farmington, approximately 40 miles east of the Arizona-New Mexico border.

APS' present generating facilities have an accredited capacity aggregating 3,987,300 kilowatts, comprised as follows:

Coal:	Capacity (kW)
Units 1, 2 and 3 at Four Corners, aggregating	560,000
15% owned Units 4 and 5 at Four Corners, representing	222,000
Units 1, 2, and 3 at the Cholla Plant, aggregating	615,000
14% owned Units 1, 2 and 3 at the Navajo Plant, representing	315,000
	1,712,000
Gas or Oil:	
Two steam units at Ocotillo and two steam units at Saguaro, aggregating	435,000(1)
Eleven combustion turbine units, aggregating	493,000
Three combined cycle units, aggregating	255,000
	1,183,000
Nuclear:	
29.1 % owned or leased Units 1, 2 and 3 at Palo Verde, representing	1,086,300
Hydro and Solar	6,000

(1) West Phoenix steam units (108,300 kw) are currently mothballed.

APS' transmission facilities consist of approximately 4,855 pole miles of overhead lines and approximately 20 miles of underground lines, all of which are located within the State of Arizona. APS' distribution facilities consist of approximately 11,681 pole miles of overhead lines and approximately 11,331 miles of underground lines, all of which are located within the State of Arizona.

3. THE FOLLOWING INFORMATION FOR THE LAST CALENDAR YEAR WITH RESPECT TO CLAIMANT AND EACH OF ITS SUBSIDIARY PUBLIC UTILITY COMPANIES:

(DATA IS NOT MAINTAINED IN A FORMAT IDENTIFYING THE STATE IN WHICH THE SALES AND PURCHASES ARE MADE OR THE AMOUNT OF THEIR ASSOCIATED REVENUES OR EXPENSES.)

a. NUMBER OF KWH OF ELECTRIC ENERGY SOLD (AT RETAIL OR WHOLESALE), AND MCF. OF NATURAL OR MANUFACTURED GAS DISTRIBUTED AT RETAIL.

44,531,881,000 kwh of electric energy sold at wholesale or retail

0 Mcf. of natural or manufactured gas distributed at wholesale or retail

b. NUMBER OF KWH OF ELECTRIC ENERGY AND MCF. OF NATURAL OR MANUFACTURED GAS DISTRIBUTED AT RETAIL OUTSIDE THE STATE IN WHICH EACH SUCH COMPANY IS ORGANIZED.

63,234,000 kwh of electric energy was distributed at retail outside Arizona

0 Mcf. of natural or manufactured gas distributed at retail outside Arizona

c. NUMBER OF KWH OF ELECTRIC ENERGY AND MCF. OF NATURAL OR MANUFACTURED GAS SOLD AT WHOLESALE OUTSIDE THE STATE IN WHICH EACH SUCH COMPANY IS ORGANIZED, OR AT THE STATE LINE.

1,663,868,000 kwh of electric energy was sold at wholesale outside Arizona or at state line (excluding power marketing activities).

2,444,508 Mcf. of natural or manufactured gas sold at wholesale outside Arizona or at state line (excluding power marketing activities).

d. NUMBER OF KWH OF ELECTRIC ENERGY AND MCF. OF NATURAL OR MANUFACTURED GAS PURCHASED OUTSIDE THE STATE IN WHICH EACH SUCH COMPANY IS ORGANIZED OR AT THE STATE LINE.

1,149,715,000 kwh of electric energy was purchased outside Arizona or at state line (excluding power marketing activities).

30,143,707 Mcf. of natural or manufactured gas purchased outside Arizona or at state line (excluding power marketing activities).

4. THE FOLLOWING INFORMATION FOR THE REPORTING PERIOD WITH RESPECT TO CLAIMANT AND EACH INTEREST IT HOLDS DIRECTLY OR INDIRECTLY IN AN EWG OR A FOREIGN UTILITY COMPANY, STATING MONETARY AMOUNTS IN UNITED STATES DOLLARS:

The Claimant holds no interest, direct or indirect, in an EWG or a foreign utility company.

a. NAME, LOCATION, BUSINESS ADDRESS AND DESCRIPTION OF THE FACILITIES USED BY THE EWG OR FOREIGN UTILITY COMPANY FOR THE GENERATION, TRANSMISSION AND DISTRIBUTION OF ELECTRIC ENERGY FOR SALE OR FOR THE DISTRIBUTION AT RETAIL OF NATURAL OR MANUFACTURED GAS.

Not applicable.

b. NAME OF EACH SYSTEM COMPANY THAT HOLDS AN INTEREST IN SUCH EWG OR FOREIGN UTILITY COMPANY; AND DESCRIPTION OF THE INTEREST HELD.

Not applicable.

c. TYPE AND AMOUNT OF CAPITAL INVESTED, DIRECTLY OR INDIRECTLY, BY THE HOLDING COMPANY CLAIMING EXEMPTION; ANY DIRECT OR INDIRECT GUARANTEE OF THE SECURITY OF THE EWG OR FOREIGN UTILITY COMPANY BY THE HOLDING COMPANY CLAIMING EXEMPTION; AND ANY DEBT OR OTHER FINANCIAL OBLIGATION FOR WHICH THERE IS RECOURSE, DIRECTLY OR INDIRECTLY, TO THE HOLDING COMPANY CLAIMING EXEMPTION OR ANOTHER SYSTEM COMPANY, OTHER THAN THE EWG OR FOREIGN UTILITY COMPANY.

Not applicable.

d. CAPITALIZATION AND EARNINGS OF THE EWG OR FOREIGN UTILITY COMPANY DURING THE REPORTING PERIOD.

Not applicable.

e. IDENTIFY ANY SERVICE, SALES OR CONSTRUCTION CONTRACT(S) BETWEEN THE EWG OR FOREIGN UTILITY COMPANY AND A SYSTEM COMPANY, AND DESCRIBE THE SERVICES TO BE RENDERED OR GOODS SOLD AND FEES OR REVENUES UNDER SUCH AGREEMENT(S).

Not applicable.

EXHIBIT A

A CONSOLIDATING STATEMENT OF INCOME AND SURPLUS OF THE CLAIMANT AND ITS SUBSIDIARY COMPANIES FOR THE LAST CALENDAR YEAR, TOGETHER WITH A CONSOLIDATING BALANCE SHEET OF CLAIMANT AND ITS SUBSIDIARY COMPANIES AS OF THE CLOSE OF SUCH CALENDAR YEAR.

Exhibit A hereto includes consolidating statements of income and consolidating balance sheets for the Claimant and the following of its subsidiaries: Arizona Public Service Company, SunCor Development Company, El Dorado Investment Company, APS Energy Services Company, Inc. and Pinnacle West Energy Corporation. Subsidiaries have been consolidated for financial reporting purposes in accordance with Statement of Financial Accounting Standards No. 94, Consolidation of All Majority-Owned Subsidiaries. Also included are consolidating statements of income and consolidating balance sheets for SunCor Development Company and its subsidiaries.

EXHIBIT B FINANCIAL DATA STATEMENT

IF, AT THE TIME A REPORT ON THIS FORM IS FILED, THE REGISTRANT IS REQUIRED TO SUBMIT THIS REPORT AND ANY AMENDMENTS THERETO ELECTRONICALLY VIA EDGAR, THE REGISTRANT SHALL FURNISH A FINANCIAL DATA SCHEDULE. THE SCHEDULE SHALL SET FORTH THE FINANCIAL AND OTHER DATA SPECIFIED BELOW THAT ARE APPLICABLE TO THE REGISTRANT ON A CONSOLIDATED BASIS.

1. TOTAL ASSETS.

2. TOTAL OPERATING REVENUES.

3. NET INCOME.

See Exhibit B hereto.

EXHIBIT C

AN ORGANIZATIONAL CHART SHOWING THE RELATIONSHIP OF EACH EWG OR FOREIGN UTILITY COMPANY TO ASSOCIATE COMPANIES IN THE HOLDING-COMPANY SYSTEM.

Not applicable.

EXHIBIT D

In accordance with Item 304 of Regulation S-T of the Securities Exchange Act of 1934, APS' Service Territory map contained as Exhibit D to this Form U-3A-2 is a map of the State of Arizona showing APS' service area, the location of its major power plants and principal transmission lines, and the location of transmission lines operated by APS for others. The major power plants shown on such map are the Navajo Generating Station located in Coconino County, Arizona; the Four Corners Power Plant located near Farmington, New Mexico; the Cholla Power Plant, located in Navajo County, Arizona; the Yucca Power Plant, located near Yuma, Arizona; and the Palo Verde Nuclear Generating Station, located about 55 miles west of Phoenix, Arizona (each of which plants is reflected on such map as being jointly owned with other utilities), as well as the Ocotillo Power Plant and West Phoenix Power Plant, each located near Phoenix, Arizona, and the Saguaro Power Plant, located near Tucson, Arizona. APS' major transmission lines shown on such map are reflected as running between the power plants named above and certain major cities in the State of Arizona. The transmission lines operated for others shown on such map are reflected as running from the Four Corners Plant through a portion of northern Arizona to the California border.

The above-named Claimant has caused this statement to be duly executed on its behalf by its authorized officer on this 28th day of February, 2001.

Pinnacle West Capital corporation

(Name of Claimant)

By Barbara M. Gomez

Barbara M. Gomez
Treasurer

[CORPORATE SEAL]

Attest:

Betsy A. Pregulman

Betsy A. Pregulman
Associate Secretary

Name, title and address of officer to whom notices and correspondence concerning this statement should be addressed:

Barbara M. Gomez	Treasurer
(Name)	(Title)

400 North Fifth Street, Station 9996, Phoenix, Arizona 85004

(Address)

PINNACLE WEST CAPITAL CORPORATION
EXHIBIT B
FINANCIAL DATA SCHEDULE
HOLDING COMPANY REPORT

12/31/00

The Claimant submits the following consolidated financial information:

1	Total Assets:	$ 7,149,151
2	Total Operating Revenues:	$ 3,690,175
3	Net Income:	$ 302,332

PINNACLE WEST CAPITAL CORPORATION
CONSOLIDATING BALANCE SHEET (unaudited)
December 31, 2000
(THOUSANDS OF DOLLARS)

	PWCC	APS	PWMT	SUNCOR	ELDO	PWE
ASSETS						
CURRENT ASSETS						
Cash and cash equivalents	$ 1,330	$ 2,609	$ 175	$ 5,149	$ 247	$ 73
Customer and other receivables - net	234,761	468,343	45,907	5,418	182	8,669
Accrued utility revenue		74,566				
Materials and supplies		71,966				
Fossil fuel		19,405				
Deferred income taxes		5,793				
Other current assets	6,692	55,920		34,439		2
Total current assets	242,783	698,602	46,082	45,006	429	8,744
INVESTMENTS AND OTHER ASSETS						
Real estate investments, net (cap interest) 1145.1				372,103		
Other assets	2,478,599	269,678		7,413	20,999	
Total investments and other	2,478,599	269,678		379,516	20,999	
PROPERTY, PLANT AND EQUIPMENT						
Plant in service		7,805,025				
Nuclear Fuel		47,389				
Construction work in progress		245,749	20			218,663
Total		8,038,163	20			218,663
Less accumulated depreciation and amortization		3,187,328				
Net Property, Plant and Equipment		4,910,835	20			218,663
DEFERRED DEBITS						
Deferred income taxes				26,920		
Regulatory asset for income taxes						
Regulatory assets		469,867				
Other deferred debits		50,733	192	10,464		1,140
Total deferred debits		520,600	192	37,384		1,140
TOTAL ASSETS	$2,721,382	$6,399,715	$ 46,294	$ 461,906	$ 21,428	$ 228,547

	ENERGY SERVICES	*ELIMINATIONS AND ADJUSTING ENTRIES* DEBIT	CREDIT	TOTAL
ASSETS				
CURRENT ASSETS				
Cash and cash equivalents	$ 780			$ 10,363
Customer and other receivables - net	15,265		$ 264,723 (b)	513,822
Accrued utility revenue				74,566
Materials and supplies				71,966
Fossil fuel				19,405
Deferred income taxes				5,793
Other current assets	945			97,998
Total current assets	16,990		264,723	793,913
INVESTMENTS AND OTHER ASSETS				
Real estate investments, net (cap interest) 1145.1		$ 4,849 (f)	5,629 (e)	371,323
Other assets	2,199		2,460,639 (a,f,h)	318,249
Total investments and other	2,199	4,849	2,466,268	689,572
PROPERTY, PLANT AND EQUIPMENT				
Plant in service	4,541			7,809,566
Nuclear Fuel				47,389
Construction work in progress	108			464,540
Total	4,649			8,321,495
Less accumulated depreciation and amortization	974			3,188,302
Net Property, Plant and Equipment	3,675			5,133,193
DEFERRED DEBITS				
Deferred income taxes			26,920 (c)	
Regulatory asset for income taxes				
Regulatory assets				469,867
Other deferred debits		77 (h)		62,606
Total deferred debits		77	26,920	532,473
TOTAL ASSETS	$ 22,864	$ 4,926	$2,757,911	$7,149,151

PINNACLE WEST CAPITAL CORPORATION
CONSOLIDATING BALANCE SHEET
December 31, 2000
(THOUSANDS OF DOLLARS)

	PWCC	APS	PWMT	SUNCOR	ELDO	PWE
LIABILITIES AND EQUITY						
CURRENT LIABILITIES						
Accounts payable	$ 12,609	$ 267,999	$ 51,033	$ 15,211	$ 129	$ 13,372
Accrued taxes		106,515	(1,870)		3,228	
Accrued interest	2,647	39,488		819		
Short-term borrowings		82,100				
Current maturities of long-term debt	213,000	250,266		203		
Customer Deposits		24,498		1,691		
Other current liabilities	30,192	142,126		5,936	157	201,990
Total current liabilities	258,448	912,992	49,163	23,860	3,514	215,362
NON-CURRENT LIABILITIES						
Long-term debt less current maturities	25,000	1,806,908		123,175		
Total	25,000	1,806,908		123,175		
DEFERRED CREDITS AND OTHER						
Deferred income taxes	39,318	1,110,437			1,546	
Unamortized gain		68,636				
Other	15,902	380,974		6,686		
Total deferred credits	55,220	1,560,047		6,686	1,546	
COMMITMENTS AND CONTINGENCIES (NOTE)						
MINORITY INTERESTS:						
Non-Redeemable preferred stock of APS						
Redeemable preferred stock of APS						
Joint Ventures of SunCor				5,629		
COMMON STOCK EQUITY:						
Common stock	2,005,932	1,424,966		356,391	14,046	15,626
Accumulated deficit	376,782	694,802	(2,869)	(53,835)	2,322	(2,441)
Total	2,382,714	2,119,768	(2,869)	302,556	16,368	13,185
TOTAL LIABILITIES AND EQUITY	$2,721,382	$6,399,715	$ 46,294	$ 461,906	$ 21,428	$ 228,547

	ENERGY SERVICES	*ELIMINATIONS* DEBIT	*ELIMINATIONS* CREDIT	TOTAL
LIABILITIES AND EQUITY				
CURRENT LIABILITIES				
Accounts payable	$ 15,472	$ 20 (I,p)		$ 375,805
Accrued taxes	12	18,659 (k)	$ 20 (i)	89,246
Accrued interest				42,954
Short-term borrowings	675	(m)		82,775
Current maturities of long-term debt				463,469
Customer Deposits				26,189
Other current liabilities		269,541 (b,g)		110,860
Total current liabilities	16,159	288,220	20	1,191,298
NON-CURRENT LIABILITIES				
Long-term debt less current maturities				1,955,083
Other liabilites				
Total				1,955,083
DEFERRED CREDITS AND OTHER				
Deferred income taxes			(8,261) (k,o)	1,143,040
Unamortized gain				68,636
Other			4,818 (g)	408,380
Total deferred credits			(3,443)	1,620,056
COMMITMENTS AND CONTINGENCIES (NOTE)				
MINORITY INTERESTS:				
Non-Redeemable preferred stock of APS				
Redeemable preferred stock of APS				
Joint Ventures of SunCor		5,629 (e)		
COMMON STOCK EQUITY:				
Common stock	29,060	2,313,190 (a)		1,532,831
Accumulated deficit	(22,355)		(142,523) (a)	849,883
Total	6,705	2,313,190	(142,523)	2,382,714
TOTAL LIABILITIES AND EQUITY	$ 22,864	$2,607,039	$ (145,946)	$7,149,151

ADJUSTING AND ELIMINATION ENTRIES
DECEMBER 31, 2000

(a)	Common stock	$2,313,190	
	Accumulated deficit		$ (142,523)
	Other investments		2,455,713

To eliminate PNW investment in subsidiaries

	Common Stock	Earnings/ Dividends	Total
APS	$1,898,067	$ 221,701	$2,119,768
Power Marketing		(2,869)	(2,869)
Pinnacle West Energy	15,626	(2,441)	13,185
Energy Services	29,060	(22,355)	6,705
SunCor	356,391	(53,835)	302,556
El Dorado	14,046	2,322	16,368
Total	$2,313,190	$ 142,523	$2,455,713

(b)	Other current liabilities	$ 264,723	
	Customer and other receivables - net		$ 264,723

To eliminate intercompany receivables/payables between all entities

	Intercompany Receivables	Intercompany Payables
Pinnacle West CC	$ 236,628	$ 236,628
APS	24,463	24,463
Pinnacle West Energy	1,086	1,086
Energy Services	488	488
Power Marketing	1,484	1,484
Palo Verde (50)	497	497
Four Corners (10)	47	47
Cholla (30)	30	30
Total	$ 264,723	$ 264,723

(e)	Minority interest	$ 5,629	
	Real estate investments - net		$ 5,629

To eliminate minority interest of SunCor JV partners

(f)	Real estate investments - net	$ 4,849	
	Other - assets		$ 4,849

To reclass PNW capitalized interest related to SunCor (1145.1)

(g)	Other current liabilities	$ 4,818	
	Other deferred credits		$ 4,818

To reclass PNW deferred comp to long-term (2085)

(h)	Other deferred debits	$ 77	
	Other - assets		$ 77

To relcass PNW unamortized debt to long-term (1130-1131)

ADJUSTING AND ELIMINATION ENTRIES
DECEMBER 31, 2000

(i)	Accounts payable	$ 20	
	Accrued taxes		$ 20
	To reclass PNW property tax (2002.1)		
(k)	Accrued taxes	$ 18,659	
	Other deferred debits		$ 18,659
	To reclass PNW accrued taxes (2090)		
(o)	Deferred income taxes-current portion	$ --	
	Deferred income taxes-noncurrent portion	26,920	
	Deferred income taxes		$ 26,920

PINNACLE WEST CAPITAL CORPORATION
CONSOLIDATING INCOME STATEMENT (unaudited)
FOR THE PERIODS ENDED DECEMBER 31,
(THOUSANDS OF DOLLARS)

	PWCC	APS	PWMT	SUNCOR	ELDO
OPERATING REVENUES:					
Electric		$ 3,480,252	$ 52,337		
Real Estate				$ 158,365	
Total	--	3,480,252	52,337	158,365	--
FUEL EXPENSES:					
Fuel for electric generation		333,265	--		
Purchased power		1,547,464	54,054		
Total	--	1,880,729	54,054	--	--
OPERATING EXPENSES:					
Utility operations and maintenance		430,696	3,016		
Real estate operations				134,279	
Depreciation and amortization	$ 266	388,660	6	4,657	--
Taxes other than income taxes		99,730	--		
Total	266	919,086	3,022	138,936	--
OPERATING INCOME	(266)	680,437	(4,739)	19,429	--
OTHER INCOME (DEDUCTIONS):					
Energy Services		--	--		
Interest on long-term debt	(11,472)	(134,431)	--	(10,672)	--
Other interest	(1,012)	(14,352)	--	--	--
Capitalized interest	31	10,894	--	6,202	--
Preferred stock dividend requirements		--	--		
Other, net	305,998	(10,637)	--	4,343	3,677
Total	293,545	(148,526)	--	(127)	3,677
Income from continuing operations b4 income taxes	293,279	531,911	(4,739)	19,302	3,677
Income Tax Expense (Benefit)	(9,053)	225,317	(1,870)	7,764	1,694
Income from continuing operations	302,332	306,594	(2,869)	11,538	1,983
Extraordinary charge	--	--			
discontinued operations	--				
Accounting change	--	--	--	--	--
NET INCOME (LOSS)	$ 302,332	$ 306,594	$ (2,869)	$ 11,538	$ 1,983

			ADJUSTMENTS & ELIMINATIONS		
	PWE	ENERGY SERVICES	DEBIT	CREDIT	TOTAL
OPERATING REVENUES:					
Electric		$ 24,859	$ 25,638(f)		$ 3,531,810
Real Estate					158,365
Total		24,859	25,638	--	3,690,175
FUEL EXPENSES:					
Fuel for electric generation					333,265
Purchased power		25,638		25,638(f)	1,601,518
Total		25,638	--	25,638	1,934,783
OPERATING EXPENSES:					
Utility operations and maintenance	2,441	14,656			450,809
Real estate operations			143(b)	--	134,422
Depreciation and amortization		821			394,410
Taxes other than income taxes			50(c)		99,780
Total	2,441	15,477	193	--	1,079,421
OPERATING INCOME	(2,441)	(16,256)	25,445	(25,638)	675,971
OTHER INCOME (DEDUCTIONS):					
Energy Services					
Interest on long-term debt				159(h)	(156,416)
Other interest	(4,487)	(24)		5,052(e,g)	(14,823)
Capitalized interest	4,487	24			21,638
Preferred stock dividend requirements					
Other, net		3,090	306,850(a,e,g,h)	193(b,c)	(186)
Total	--	3,090	306,850	5,404	(149,787)
Income from continuing operations b4 income taxes	(2,441)	(13,166)	281,405	(20,234)	526,184
Income Tax Expense (Benefit)					223,852
Income from continuing operations	(2,441)	(13,166)	281,405	(20,234)	302,332
Extraordinary charge					
discontinued operations					
Accounting change			--	--	
NET INCOME (LOSS)	$ (2,441)	$ (13,166)	$ 281,405	$ (20,234)	$ 302,332

ADJUSTING AND ELIMINATING ENTRIES
FOR THE PERIODS ENDED DECEMBER 31,

(a)	Other - net (Subs income)		$ 301,639	
	Retained Earnings			$ 301,639

To eliminate PWCC Equity in earnings from subsidiairies

	PWCC
APS	$ 306,594
PWMT	$ (2,869)
Pinnacle West Energy	(2,441)
Energy Services	(13,166)
SunCor	11,538
El Dorado	1,983
Total	$ 301,639

(b)	Real Estate Operations		$ 143	
	Interest Expense (PWCC) 5849.0097			$ 143

To reclass Capitalized Interest for SunCor Land Sales.

(c)	Taxes other than income taxes		$ 50	
	Other - net			$ 50

To reclass PNW property taxes (650051)

(e)	Other, net (El Dorado interest income)		$ 542	
	Other interest			$ 542

To eliminate interest on ELD loan to PNW (650095)

(f)	Electricity Sales		$ 25,638	
	Purchased Power			$ 25,638

To eliminate sales from APS to APSES

NOTE: As of July APSES is purchasing all power from SRP, in the future they will resume purchasing power from APS and we will have to eliminate.

(g)	Interest Income - PNW		$ 4,510	
	Interest Expense - PWE			$ 4,510

To eliminate interest expense/income on loan from PNW to PWE

(h)	Interest Income - PNW		$ 159	
	Interest Expense - Suncor			$ 159

To eliminate interest expense/income on unpaid Suncor dividend

SUNCOR DEVELOPMENT COMPANY
CONSOLIDATED BALANCE SHEET (unaudited)
31-DEC-00

ACCOUNT DESCRIPTION	1000 SUNCOR	SCOTT D. LPSCO	LENA M. RANCHLAND	PAUL N. SASI	3500 SMLP
CURRENT ASSETS					
CASH AND SHORT TERM INVESTMENTS	5,402,595	897,193	395,400	300,904	260,662
ACCOUNTS RECEIVABLE	85,856	375,064	14,396	113,166	
INTERCOMPANY ACCOUNTS:					
SASI					
LPSCO	15,731				
CORAL CANYON	650,044				
SMLP	12,492				
PVGC					
CORAL CANYON GOLF					
CC DEVELOPMENT FROM CC GOLF COURSE					
WWOS	(92,907)				
GOLDEN HERITAGE - GENERAL 129	2,634,962				
SCM-GENERAL 129	6,881,947				
HOMEBUILDING I/C INTEREST 12904	5,748,529				
HOMEBUILDING CASH ADVANCES	5,184,808				
COMMERCIAL - GENERAL					
SUNRIDGE - DEVELOPMENT	103,351				
SUNRIDGE - GOLF	194,492				
SEDONA - DEVELOPMENT	29,014				
SEDONA - GOLF	134,069				
CLUB WEST	221,941				
WIGWAM RESORT	51,837				
HFS FINANCIAL SERVICES	7,966				
WESTWORLD DEVELOPMENT	450				
SANCTUARY GOLF	144,333				
INTEREST RECEIVABLE	350,634				
NOTES RECEIVABLE	102,032				
INVENTORIES					
PREPAID EXPENSES	22,211				
HOME INVENTORY GOLDEN HERITAGE	6,888				
HOME INVENTORY RANCHO VIEJO					
HOME INVENTORY CORAL CANYON					
TOTAL CURRENT ASSETS	27,893,276	1,272,257	409,797	414,070	260,662
LONG-TERM ASSETS					
DEVELOPMENT PROJECTS					
CORAL CANYON					
HIDDEN HILLS					
RANCHO VIEJO					
PALM VALLEY					
LITCHFIELD GREENS					
VILLAGE OF LITCHFIELD GREENS					
SCOTTSDALE MOUNTAIN					3,300,313
MARKETPLACE - AUTOPLEX					
TATUM RANCH	498,513				
TALAVI					
WIGWAM OUTLET STORES					
GOLDEN HERITAGE					
BILTMORE ESTATES					
BLACK CANYON COMMERCE PARK					
OTHER COMMERCIAL LAND					
EQUITY INVESTMENTS:					
EQUITY IN CTRPT ASSOC-LLP					
INVEST IN HAYDEN FERRY LAKESIDE					
INVEST IN KYRENE ASSOCIATES LLC					
INVEST IN PV APARTMENTS (I & II)					
INVESTMENT IN SUNRIDGE CANYON LLC	1,431,298				
INVESTMENT IN SEDONA GOLF LC	4,856,237				
INVEST IN TALAVI ASSOCIATES LLC					
INVESTMENT IN SANCTUARY GOLF	3,734,146				
INVESTMENT IN HFS MORTGAGE					
CONSOLIDATED ELIMINATING ENTITIES:					
INVEST IN KABUTO/SUNCOR JV	6,616,664				
INVEST IN SCOTTS MTN LTD PART	2,307,567				
INVEST IN GOLDEN HERITAGE	6,640,236				
GOLDEN HERITAGE DUE DILIGENCE					
INVESTMENT IN SCM	517,850				
INVESTMENT IN LPSCO	15,473,739				
INVESTMENT IN SASI					
INVESTMENT IN PALM VALLEY	151,156,985				
INVESTMENT IN PALM VALLEY GOLF	4,744,115				
INVESTMENT IN CLUB WEST G.C.	3,259,883				
PALM VALLEY GOLF CONTRIB. CAP	4,940,770				
INVESTMENT IN CORAL CANYON GOLF	(153,937)				
INVESTMENT IN RANCHO VIEJO	18,763,648				
INVESTMENT IN RANCHLAND UTILITY	(152,101)				
INVESTMENT IN HIDDEN HILLS	11,382,590				
INVESTMENT IN CORAL CANYON	26,874,578				
INVESTMENT IN FIDDLESTICKS-SCOTTS	(2,571,350)				
INVESTMENT IN FIDDLESTICKS-TEMPE	(404,512)				
INVESTMENT IN FUNTASTICKS	146,585				
INVESTMENT IN GENERAL COMM OPS	82,369,699				
INVESTMENT IN PV MARKETPLACE	3,473,608				
INVESTMENT IN DYSART/MCDOWELL	872,112				
INVESTMENT IN PV PAVILIONS	3,821,322				
INVESTMENT IN PV CROSSING	1,306,479				
INVESTMENT IN PALM VALLEY OFFICE PARK	247,225				
INVESTMENT IN AUTOPLEX	(148,809)				
INVESTMENT IN TALAVI	(221,422)				
INVESTMENT IN METROCENTER	281,411				
INVESTMENT IN RESTORATION PLACE	(178,047)				
INVESTMENT IN LITCHFIELD PARK OPS	168,239				
INVESTMENT IN LP PROF. PLAZA	6,876				
INVESTMENT IN WWOS LLC	(1,319,040)				
INVESTMENT IN APS PROPERTIES	422,040				
INVESTMENT IN BLACK CANYON CP	741,506				
COMMERCIAL PROPERTIES					

WWOS					
LONG-TERM NOTES RECEIVABLE	3,574,077				
SDC PHASE I LAND NOTE TO WWOS	962,496				
SDC PAYOFF OF WWOS RLC	10,000,000				
SDC LOAN TO LPSCO	300,000				
PROPERTY & EQUIPMENT, NET	770,821			36,696	
DEFERRED ASSETS	5,314,755	321,468	33,279		
DEFERRED INCOME TAXES	26,533,921				
WATER & SEWER UTILITY PROP, NET		22,254,148	1,149,961		
LPSCO RESTRICTED CASH FUNDS		2,394,649			
RANCHO VIEJO RESTRICTED CASH FUNDS					
SCOTTSDALE MOUNTAIN RESTRICTED CASH FUNDS					
DEPOSITS					
TOTAL LONG-TERM ASSETS	399,362,773	24,970,265	1,183,240	36,696	3,300,313
TOTAL ASSETS	427,256,049	26,242,522	1,593,036	450,766	3,560,975

ACCOUNT DESCRIPTION	LINDA H. PVGC	TONYA CLUB WEST	GAYE LYNN CC GOLF	LARRY W. GHH	5500 PV
CURRENT ASSETS					
CASH AND SHORT TERM INVESTMENTS	43,711	131,857	38,384	89,108	(597,619)
ACCOUNTS RECEIVABLE	30,741	11,879	12,927	708,060	(6,165)
INTERCOMPANY ACCOUNTS:					
SASI					
LPSCO					
CORAL CANYON					
SMLP					
PVGC	(4,940,770)				
CORAL CANYON GOLF			(54,809)		
CC DEVELOPMENT FROM CC GOLF COURSE					
WWOS					
GOLDEN HERITAGE - GENERAL 129				(1,202,697)	
SCM-GENERAL 129				(6,881,947)	
HOMEBUILDING I/C INTEREST 12904				(5,748,529)	
HOMEBUILDING CASH ADVANCES					
COMMERCIAL - GENERAL					
SUNRIDGE - DEVELOPMENT					
SUNRIDGE - GOLF					
SEDONA - DEVELOPMENT					
SEDONA - GOLF					
CLUB WEST					
WIGWAM RESORT					
HFS FINANCIAL SERVICES					
WESTWORLD DEVELOPMENT					
SANCTUARY GOLF					
INTEREST RECEIVABLE					
NOTES RECEIVABLE					
INVENTORIES	87,838	81,616	52,335		
PREPAID EXPENSES	42,756	7,315	200	24,342	
HOME INVENTORY GOLDEN HERITAGE				30,168,781	
HOME INVENTORY RANCHO VIEJO					
HOME INVENTORY CORAL CANYON					
TOTAL CURRENT ASSETS	(4,735,724)	232,667	49,036	17,157,117	(603,783)
LONG-TERM ASSETS					
DEVELOPMENT PROJECTS					
CORAL CANYON					
HIDDEN HILLS					
RANCHO VIEJO					
PALM VALLEY					153,033,673
LITCHFIELD GREENS					68,157
VILLAGE OF LITCHFIELD GREENS					
SCOTTSDALE MOUNTAIN					
MARKETPLACE - AUTOPLEX					
TATUM RANCH					
TALAVI					
WIGWAM OUTLET STORES					
GOLDEN HERITAGE					
BILTMORE ESTATES					
BLACK CANYON COMMERCE PARK					
OTHER COMMERCIAL LAND					
EQUITY INVESTMENTS:					
EQUITY IN CTRPT ASSOC-LLP					
INVEST IN HAYDEN FERRY LAKESIDE					
INVEST IN KYRENE ASSOCIATES LLC					
INVEST IN PV APARTMENTS (I & II)					275,488
INVESTMENT IN SUNRIDGE CANYON LLC					
INVESTMENT IN SEDONA GOLF LC					
INVEST IN TALAVI ASSOCIATES LLC					
INVESTMENT IN SANCTUARY GOLF					
INVESTMENT IN HFS MORTGAGE					
CONSOLIDATED ELIMINATING ENTITIES:					
INVEST IN KABUTO/SUNCOR JV					
INVEST IN SCOTTS MTN LTD PART					
INVEST IN GOLDEN HERITAGE					
GOLDEN HERITAGE DUE DILIGENCE					
INVESTMENT IN SCM					
INVESTMENT IN LPSCO					
INVESTMENT IN SASI					235,243
INVESTMENT IN PALM VALLEY					
INVESTMENT IN PALM VALLEY GOLF					
INVESTMENT IN CLUB WEST G.C.					
PALM VALLEY GOLF CONTRIB. CAP					
INVESTMENT IN CORAL CANYON GOLF					
INVESTMENT IN RANCHO VIEJO					
INVESTMENT IN RANCHLAND UTILITY					
INVESTMENT IN HIDDEN HILLS					
INVESTMENT IN CORAL CANYON					
INVESTMENT IN FIDDLESTICKS-SCOTTS					
INVESTMENT IN FIDDLESTICKS-TEMPE					
INVESTMENT IN FUNTASTICKS					
INVESTMENT IN GENERAL COMM OPS					
INVESTMENT IN PV MARKETPLACE					
INVESTMENT IN DYSART/MCDOWELL					
INVESTMENT IN PV PAVILIONS					
INVESTMENT IN PV CROSSING					

INVESTMENT IN PALM VALLEY OFFICE PARK					
INVESTMENT IN AUTOPLEX					
INVESTMENT IN TALAVI					
INVESTMENT IN METROCENTER					
INVESTMENT IN RESTORATION PLACE					
INVESTMENT IN LITCHFIELD PARK OPS					
INVESTMENT IN LP PROF. PLAZA					
INVESTMENT IN WWOS LLC					
INVESTMENT IN APS PROPERTIES					
INVESTMENT IN BLACK CANYON CP					
COMMERCIAL PROPERTIES	12,382,937	8,478,448	6,395,332		
WWOS					
LONG-TERM NOTES RECEIVABLE					498,808
SDC PHASE I LAND NOTE TO WWOS					
SDC PAYOFF OF WWOS RLC					
SDC LOAN TO LPSCO					
PROPERTY & EQUIPMENT, NET	397,125		288,460	867,751	290,466
DEFERRED ASSETS	149,715				144,112
DEFERRED INCOME TAXES					
WATER & SEWER UTILITY PROP, NET					
LPSCO RESTRICTED CASH FUNDS					
RANCHO VIEJO RESTRICTED CASH FUNDS					
SCOTTSDALE MOUNTAIN RESTRICTED CASH FUNDS					
DEPOSITS				62,330	
TOTAL LONG-TERM ASSETS	12,929,777	8,478,448	6,683,792	930,081	154,545,948
TOTAL ASSETS	8,194,053	8,711,115	6,732,828	18,087,198	153,942,164

ACCOUNT DESCRIPTION	5501 KABUTO JV	COMM.	3300 H HILLS	R. VIEJO JOYCE L.	3900 C. CANYON
CURRENT ASSETS					
CASH AND SHORT TERM INVESTMENTS	5,182	(928,950)	(101,122)	(312,157)	(475,687)
ACCOUNTS RECEIVABLE		598,897		200,169	500,275
INTERCOMPANY ACCOUNTS:					
SASI					
LPSCO					
CORAL CANYON					
SMLP					
PVGC					
CORAL CANYON GOLF					
CC DEVELOPMENT FROM CC GOLF COURSE					6,840,673
WWOS					
GOLDEN HERITAGE - GENERAL 129					
SCM-GENERAL 129					
HOMEBUILDING I/C INTEREST 12904					
HOMEBUILDING CASH ADVANCES					
COMMERCIAL - GENERAL					
SUNRIDGE - DEVELOPMENT					
SUNRIDGE - GOLF					
SEDONA - DEVELOPMENT					
SEDONA - GOLF					
CLUB WEST					
WIGWAM RESORT					
HFS FINANCIAL SERVICES					
WESTWORLD DEVELOPMENT					
SANCTUARY GOLF					
INTEREST RECEIVABLE					
NOTES RECEIVABLE					208,620
INVENTORIES		40,362			
PREPAID EXPENSES		11,324		450	115,455
HOME INVENTORY GOLDEN HERITAGE					
HOME INVENTORY RANCHO VIEJO				4,430,162	
HOME INVENTORY CORAL CANYON					2,449,435
TOTAL CURRENT ASSETS	5,182	(278,367)	(101,122)	4,318,624	9,638,771
LONG-TERM ASSETS					
DEVELOPMENT PROJECTS					
CORAL CANYON					17,678,943
HIDDEN HILLS			17,088,092		
RANCHO VIEJO				13,869,468	
PALM VALLEY		15,792,205			
LITCHFIELD GREENS					
VILLAGE OF LITCHFIELD GREENS	13,839,065				
SCOTTSDALE MOUNTAIN					
MARKETPLACE - AUTOPLEX		4,913,292			
TATUM RANCH					
TALAVI		782,548			
WIGWAM OUTLET STORES					
GOLDEN HERITAGE					
BILTMORE ESTATES					
BLACK CANYON COMMERCE PARK		1,474,224			
OTHER COMMERCIAL LAND		2,124,954			
EQUITY INVESTMENTS:					
EQUITY IN CTRPT ASSOC-LLP		22,080,662			
INVEST IN HAYDEN FERRY LAKESIDE		3,132,793			
INVEST IN KYRENE ASSOCIATES LLC					
INVEST IN PV APARTMENTS (I & II)					
INVESTMENT IN SUNRIDGE CANYON LLC					
INVESTMENT IN SEDONA GOLF LC					
INVEST IN TALAVI ASSOCIATES LLC		2,500,094			
INVESTMENT IN SANCTUARY GOLF					
INVESTMENT IN HFS MORTGAGE					
CONSOLIDATED ELIMINATING ENTITIES:					
INVEST IN KABUTO/SUNCOR JV					
INVEST IN SCOTTS MTN LTD PART					
INVEST IN GOLDEN HERITAGE					
GOLDEN HERITAGE DUE DILIGENCE					
INVESTMENT IN SCM					
INVESTMENT IN LPSCO					
INVESTMENT IN SASI					
INVESTMENT IN PALM VALLEY					
INVESTMENT IN PALM VALLEY GOLF					
INVESTMENT IN CLUB WEST G.C.					
PALM VALLEY GOLF CONTRIB. CAP					
INVESTMENT IN CORAL CANYON GOLF					
INVESTMENT IN RANCHO VIEJO					
INVESTMENT IN RANCHLAND UTILITY				1,109,212	

INVESTMENT IN HIDDEN HILLS					
INVESTMENT IN CORAL CANYON					
INVESTMENT IN FIDDLESTICKS-SCOTTS					
INVESTMENT IN FIDDLESTICKS-TEMPE					
INVESTMENT IN FUNTASTICKS					
INVESTMENT IN GENERAL COMM OPS					
INVESTMENT IN PV MARKETPLACE					
INVESTMENT IN DYSART/MCDOWELL					
INVESTMENT IN PV PAVILIONS					
INVESTMENT IN PV CROSSING					
INVESTMENT IN PALM VALLEY OFFICE PARK					
INVESTMENT IN AUTOPLEX					
INVESTMENT IN TALAVI					
INVESTMENT IN METROCENTER					
INVESTMENT IN RESTORATION PLACE					
INVESTMENT IN LITCHFIELD PARK OPS					
INVESTMENT IN LP PROF. PLAZA					
INVESTMENT IN WWOS LLC					
INVESTMENT IN APS PROPERTIES					
INVESTMENT IN BLACK CANYON CP					
COMMERCIAL PROPERTIES		34,090,144			
WWOS		13,806,739			
LONG-TERM NOTES RECEIVABLE					
SDC PHASE I LAND NOTE TO WWOS					
SDC PAYOFF OF WWOS RLC					
SDC LOAN TO LPSCO					
PROPERTY & EQUIPMENT, NET				168,808	519,401
DEFERRED ASSETS		1,441,156			1,989
DEFERRED INCOME TAXES					
WATER & SEWER UTILITY PROP, NET				264,261	
LPSCO RESTRICTED CASH FUNDS					
RANCHO VIEJO RESTRICTED CASH FUNDS				600,357	
SCOTTSDALE MOUNTAIN RESTRICTED CASH FUNDS					
DEPOSITS					
TOTAL LONG-TERM ASSETS	13,839,065	102,138,809	17,088,092	16,012,106	18,200,333
TOTAL ASSETS	13,844,247	101,860,441	16,986,970	20,330,730	27,839,104

CONSOLIDATING & ELIMINATING ENTRIES

ACCOUNT DESCRIPTION	REF	DEBIT	REF	CREDIT	CONSOLIDATED
CURRENT ASSETS					
CASH AND SHORT TERM INVESTMENTS					5,149,460.86
ACCOUNTS RECEIVABLE			Y	177,220	2,468,046.09
INTERCOMPANY ACCOUNTS:					
SASI					0.00
LPSCO			H	15,731	0.00
CORAL CANYON			X	650,044	0.00
SMLP			J	12,492	0.00
PVGC	N	4,940,770			0.00
CORAL CANYON GOLF	AA	54,809			0.00
CC DEVELOPMENT FROM CC GOLF COURSE			AA	6,840,673	0.00
WWOS	Q	92,907			0.00
GOLDEN HERITAGE - GENERAL 129	A	1,202,697	A	2,634,962	0.00
SCM-GENERAL 129		6,881,947	A	6,881,947	0.00
HOMEBUILDING I/C INTEREST 12904	C	5,748,529	C	5,748,529	0.00
HOMEBUILDING CASH ADVANCES			B	5,184,808	0.00
COMMERCIAL - GENERAL					0.00
SUNRIDGE - DEVELOPMENT					103,350.90
SUNRIDGE - GOLF					194,492.38
SEDONA - DEVELOPMENT					29,013.66
SEDONA - GOLF					134,068.70
CLUB WEST			Z	221,941	0.00
WIGWAM RESORT					51,837.48
HFS FINANCIAL SERVICES					7,965.90
WESTWORLD DEVELOPMENT					450.00
SANCTUARY GOLF					144,332.99
INTEREST RECEIVABLE			P	96,097	254,536.60
NOTES RECEIVABLE					310,652.44
INVENTORIES					262,150.82
PREPAID EXPENSES					224,052.95
HOME INVENTORY GOLDEN HERITAGE			E	3,101,379	27,074,290.21
HOME INVENTORY RANCHO VIEJO					4,430,162.42
HOME INVENTORY CORAL CANYON					2,449,435.00
					0.00
TOTAL CURRENT ASSETS		18,921,661		31,565,823	43,288,299.40
LONG-TERM ASSETS					
DEVELOPMENT PROJECTS					
CORAL CANYON					17,678,943.00
HIDDEN HILLS			T	4,474,530	12,613,561.57
RANCHO VIEJO					13,869,468.43
PALM VALLEY					168,825,877.83
LITCHFIELD GREENS					68,156.70
VILLAGE OF LITCHFIELD GREENS					13,839,064.56
SCOTTSDALE MOUNTAIN					3,300,312.71
MARKETPLACE - AUTOPLEX					4,913,291.55
TATUM RANCH					498,513.15
TALAVI					782,547.91
WIGWAM OUTLET STORES					0.00
GOLDEN HERITAGE					0.00
BILTMORE ESTATES					0.00
BLACK CANYON COMMERCE PARK					1,474,223.57
OTHER COMMERCIAL LAND					2,124,953.97
EQUITY INVESTMENTS:					0.00
EQUITY IN CTRPT ASSOC-LLP					22,080,661.88
INVEST IN HAYDEN FERRY LAKESIDE					3,132,792.60
INVEST IN KYRENE ASSOCIATES LLC					0.00
INVEST IN PV APARTMENTS (I & II)					275,488.32
INVESTMENT IN SUNRIDGE CANYON LLC					1,431,298.36
INVESTMENT IN SEDONA GOLF LC					4,856,237.26
INVEST IN TALAVI ASSOCIATES LLC					2,500,094.19
INVESTMENT IN SANCTUARY GOLF					3,734,146.32
INVESTMENT IN HFS MORTGAGE					0.00
CONSOLIDATED ELIMINATING ENTITIES:					0.00
INVEST IN KABUTO/SUNCOR JV			R	9,610,458	(2,993,794.72)

INVEST IN SCOTTS MTN LTD PART	I	20,413,693	I	22,727,157	(5,896.38)
INVEST IN GOLDEN HERITAGE		-	D	6,640,236	0.00
GOLDEN HERITAGE DUE DILIGENCE					0.00
INVESTMENT IN SCM			D	517,850	0.00
INVESTMENT IN LPSCO			F	15,087,805	385,934.07
INVESTMENT IN SASI	L	650,000	L	885,243	0.00
INVESTMENT IN PALM VALLEY		-	V	151,156,985	0.00
INVESTMENT IN PALM VALLEY GOLF	M	1,414,058	M	6,158,173	0.00
INVESTMENT IN CLUB WEST G.C.	Z	182,143	Z	3,442,026	0.00
PALM VALLEY GOLF CONTRIB. CAP			N	4,940,770	0.00
INVESTMENT IN CORAL CANYON GOLF	AA	208,746	AA	54,809	0.00
INVESTMENT IN RANCHO VIEJO			U	18,763,648	0.00
INVESTMENT IN RANCHLAND UTILITY	Y	152,101	Y	1,109,212	0.00
INVESTMENT IN HIDDEN HILLS			T	11,382,590	0.00
INVESTMENT IN CORAL CANYON	W	199,345	W	27,073,923	0.00
INVESTMENT IN FIDDLESTICKS-SCOTTS	S	4,393,865	S	1,822,515	0.00
INVESTMENT IN FIDDLESTICKS-TEMPE	S	1,708,971	S	1,304,459	0.00
INVESTMENT IN FUNTASTICKS	S	475,282	S	621,867	0.00
INVESTMENT IN GENERAL COMM OPS			S	82,369,699	0.00
INVESTMENT IN PV MARKETPLACE			S	3,473,608	0.00
INVESTMENT IN DYSART/MCDOWELL			S	872,112	0.00
INVESTMENT IN PV PAVILIONS			S	3,821,322	0.00
INVESTMENT IN PV CROSSING			S	1,306,479	0.00
INVESTMENT IN PALM VALLEY OFFICE PARK			S	247,225	0.00
INVESTMENT IN AUTOPLEX	S	148,809			0.00
INVESTMENT IN TALAVI	S	221,422			0.00
INVESTMENT IN METROCENTER			S	281,411	0.00
INVESTMENT IN RESTORATION PLACE	S	178,047			0.00
INVESTMENT IN LITCHFIELD PARK OPS			S	168,239	0.00
INVESTMENT IN LP PROF. PLAZA			S	6,876	0.00
INVESTMENT IN WWOS LLC	S	1,319,040			0.00
INVESTMENT IN APS PROPERTIES			S	422,040	0.00
INVESTMENT IN BLACK CANYON CP			S	741,506	0.00
COMMERCIAL PROPERTIES					61,346,861.38
WWOS					13,806,738.53
LONG-TERM NOTES RECEIVABLE					4,072,885.45
SDC PHASE I LAND NOTE TO WWOS			P	962,496	0.00
SDC PAYOFF OF WWOS RLC			P	10,000,000	0.00
SDC LOAN TO LPSCO			G	300,000	0.00
PROPERTY & EQUIPMENT, NET					3,339,527.65
DEFERRED ASSETS					7,406,474.15
DEFERRED INCOME TAXES					26,533,921.39
WATER & SEWER UTILITY PROP, NET					23,668,369.51
LPSCO RESTRICTED CASH FUNDS					2,394,648.90
RANCHO VIEJO RESTRICTED CASH FUNDS					600,356.97
SCOTTSDALE MOUNTAIN RESTRICTED CASH FUNDS					0.00
					0.00
DEPOSITS					62,330.00
TOTAL LONG-TERM ASSETS		31,665,522		392,747,268	418,617,990.78
TOTAL ASSETS		50,587,183		424,313,091	461,906,290.18

SUNCOR DEVELOPMENT COMPANY
CONSOLIDATED BALANCE SHEET
31-DEC-00

ACCOUNT DESCRIPTION	1000 SUNCOR	SCOTT D. LPSCO	LENA M. RANCHLAND	PAUL N. SASI	3500 SMLP
LIABILITIES:					
CURRENT LIABILITIES					
A/P & RETENTION	112,349	432,083	(43)	39,817	5,066
ACCRUED LIABILITIES	4,629,880	944,416	403	133,843	10,676
INTERCOMPANY ACCOUNTS:					
LPSCO - SDC		15,731			
SMLP - SDC					12,492
SCM-SDC CASH ADVANCES 267					
GH-SDC INTERCO CAPITAL 265					
WWOS-SDC					
CLUB WEST					
CORAL CANYON					
CC GOLF COURSE TO CC DEVELOPMENT					
RANCHLAND-RANCHO VIEJO			176,174		
INTEREST PAYABLE	818,757				
S/T NOTES PAYABLE					
$45 MILLION TERM LOAN					
$55 MILLION RLC					
TEXTRON LOAN - PVGC					
DEF PROFIT & UNEARNED REVENUE	3,101,379				
PWCC INTERCO PAYABLE	210,445				
APS LAND INTERCO PAYABLE					
CUSTOMER DEPOSITS				41,864	
	8,872,810	1,392,229	176,534	215,524	28,234
LONG-TERM LIABILITIES					
LONG-TERM NOTES PAYABLE					
WWOS OWES SDC PH I LAND NOTE					
WWOS RLC PAYOFF BY SDC					
CORPORATE TERM NOTE					
CORPORATE RLC	110,000,000				
LPSCO BONDS		5,215,000			
TEXTRON LOAN - PVGC					
LOAN - CLUB WEST					
PENSION LIABILITY - SUNCOR	5,415,169				
PENSION LIABILITY - WIGWAM RESORT	310,840				
OTHER ACCRUED LIABILITIES	102,085	432,965	113,584		
DEFERRED TAXES		17,613			
LONG-TERM CUSTOMER DEPOSITS		3,796,171	346,275		
CONTRIB PROPERTY AIA					
TOTAL L/T LIABILITIES	115,828,094	9,461,749	459,859	0	0
TOTAL LIABILITIES	124,700,904	10,853,978	636,393	215,524	28,234
MINORITY INTEREST					
SDC COMMON STOCK	1,022,000				
SDC ADDITIONAL PAID IN CAPITAL	355,368,522				
SDC EARNED SURPLUS-BEGINNING	(65,374,529)				
SDC EARNED SURPLUS-CURRENT	11,539,252				
SUBSIDIARY EARNINGS-CURRENT		365,082	(60,243)	(76,048)	45,973
SUBSIDIARY EQUITY:					
LPSCO		15,023,462			
SASI				311,291	
SMLP #3500					3,486,768
PVGC					
CLUB WEST					
HOMEBUILDING					
PALM VALLEY #5500					
KABUTO JV #1000					
COMMERCIAL PROPERTIES #2000					
HIDDEN HILLS #3300					
RANCHO VIEJO #6600					
RANCHLAND UTILITY			1,016,886		
CORAL CANYON #3900					
TOTAL EQUITY	302,555,145	15,388,544	956,643	235,243	3,532,741
TOTAL LIABS AND EQUITY	427,256,049	26,242,522	1,593,036	450,767	3,560,975

ACCOUNT DESCRIPTION	LINDA H. PVGC	TONYA CLUB WEST	GAYE LYNN CC GOLF	LARRY W. GHH	5500 PV
LIABILITIES:					
CURRENT LIABILITIES					
A/P & RETENTION	73,611	50,836	30,267	2,616,983	441,477
ACCRUED LIABILITIES	43,641	56,696	72,137	270,000	829,549
INTERCOMPANY ACCOUNTS:					
LPSCO - SDC					
SMLP - SDC					
SCM-SDC CASH ADVANCES 267				5,184,808	
GH-SDC INTERCO CAPITAL 265				1,432,265	
WWOS-SDC					
CLUB WEST		221,941			
CORAL CANYON					
CC GOLF COURSE TO CC DEVELOPMENT			6,840,673		
RANCHLAND-RANCHO VIEJO					
INTEREST PAYABLE					
S/T NOTES PAYABLE					
$45 MILLION TERM LOAN					
$55 MILLION RLC					
TEXTRON LOAN - PVGC					
DEF PROFIT & UNEARNED REVENUE					
PWCC INTERCO PAYABLE					
APS LAND INTERCO PAYABLE					
CUSTOMER DEPOSITS				1,425,056	
	117,253	329,473	6,943,077	10,929,112	1,271,026
LONG-TERM LIABILITIES					
LONG-TERM NOTES PAYABLE					
WWOS OWES SDC PH I LAND NOTE					
WWOS RLC PAYOFF BY SDC					
CORPORATE TERM NOTE					
CORPORATE RLC					
LPSCO BONDS					
TEXTRON LOAN - PVGC	3,332,685				
LOAN - CLUB WEST		4,830,474			
PENSION LIABILITY - SUNCOR					
PENSION LIABILITY - WIGWAM RESORT					
OTHER ACCRUED LIABILITIES					1,514,152
DEFERRED TAXES					
LONG-TERM CUSTOMER DEPOSITS					
CONTRIB PROPERTY AIA					

TOTAL L/T LIABILITIES	3,332,685	4,830,474	0	0	1,514,152
TOTAL LIABILITIES	3,449,938	5,159,946	6,943,077	10,929,112	2,785,178
MINORITY INTEREST					
SDC COMMON STOCK					
SDC ADDITIONAL PAID IN CAPITAL					
SDC EARNED SURPLUS-BEGINNING					
SDC EARNED SURPLUS-CURRENT					
SUBSIDIARY EARNINGS-CURRENT	(952,440)	(267,857)	(210,248)	4,279,761	18,413,384
SUBSIDIARY EQUITY:					
LPSCO					
SASI					
SMLP #3500					
PVGC	5,696,556				
CLUB WEST		3,819,026			
HOMEBUILDING				2,878,324	
PALM VALLEY #5500					132,743,601
KABUTO JV #3000					
COMMERCIAL PROPERTIES #2000					
HIDDEN HILLS #3300					
RANCHO VIEJO #6600					
RANCHLAND UTILITY					
CORAL CANYON #3900					
TOTAL EQUITY	4,744,115	3,551,169	(210,248)	7,158,086	151,156,985
TOTAL LIABS AND EQUITY	8,194,053	8,711,115	6,732,829	18,087,198	153,942,163

ACCOUNT DESCRIPTION	5501 KABUTO JV	COMM.	3300 H HILLS	R. VIEJO JOYCE L.	3900 C. CANYON
LIABILITIES:					
CURRENT LIABILITIES					
A/P & RETENTION	32,619	182,016	612,629	1,113,628	262,717
ACCRUED LIABILITIES	84,320	1,336,432	517,221	229,442	46,428
INTERCOMPANY ACCOUNTS:					
LPSCO - SDC					
SMLP - SDC					
SCM-SDC CASH ADVANCES 267					
GH-SDC INTERCO CAPITAL 265					
WWOS-SDC		(92,907)			
CLUB WEST					
CORAL CANYON					655,381
CC GOLF COURSE TO CC DEVELOPMENT					
RANCHLAND-RANCHO VIEJO					
INTEREST PAYABLE		96,097			
S/T NOTES PAYABLE					
$45 MILLION TERM LOAN					
$55 MILLION RLC					
TEXTRON LOAN - PVGC					
DEF PROFIT & UNEARNED REVENUE					
PWCC INTERCO PAYABLE					
APS LAND INTERCO PAYABLE					
CUSTOMER DEPOSITS				224,013	
	116,939	1,521,639	1,129,850	1,567,083	964,526
LONG-TERM LIABILITIES					
LONG-TERM NOTES PAYABLE					
WWOS OWES SDC PH I LAND NOTE		962,496			
WWOS RLC PAYOFF BY SDC		10,000,000			
CORPORATE TERM NOTE					
CORPORATE RLC					
LPSCO BONDS					
TEXTRON LOAN - PVGC					
LOAN - CLUB WEST					
PENSION LIABILITY - SUNCOR					
PENSION LIABILITY - WIGWAM RESORT					
OTHER ACCRUED LIABILITIES		363,450			
DEFERRED TAXES					
LONG-TERM CUSTOMER DEPOSITS					
CONTRIB PROPERTY AIA					
TOTAL L/T LIABILITIES	0	11,325,947	0	0	0
TOTAL LIABILITIES	116,939	12,847,586	1,129,850	1,567,083	964,526
MINORITY INTEREST					
SDC COMMON STOCK					
SDC ADDITIONAL PAID IN CAPITAL					
SDC EARNED SURPLUS-BEGINNING					
SDC EARNED SURPLUS-CURRENT					
SUBSIDIARY EARNINGS-CURRENT	(1,919)	4,796,651	1,396,891	2,607,778	(156,726)
SUBSIDIARY EQUITY:					
LPSCO					
SASI					
SMLP #3500					
PVGC					
CLUB WEST					
HOMEBUILDING					
PALM VALLEY #5500					
KABUTO JV #3000	13,729,227				
COMMERCIAL PROPERTIES #2000		84,216,204			
HIDDEN HILLS #3300			14,460,229		
RANCHO VIEJO #6600				16,155,869	
RANCHLAND UTILITY					
CORAL CANYON #3900					27,031,304
TOTAL EQUITY	13,727,308	89,012,855	15,857,120	18,763,647	26,874,578
TOTAL LIABS AND EQUITY	13,844,247	101,860,441	16,986,970	20,330,730	27,839,104

CONSOLIDATING & ELIMINATING ENTRIES

ACCOUNT DESCRIPTION	REF	DEBIT	REF	CREDIT	CONSOLIDATED
LIABILITIES:					
CURRENT LIABILITIES					
A/P & RETENTION					6,006,056.03
ACCRUED LIABILITIES					9,205,082.56
INTERCOMPANY ACCOUNTS:					0.00
LPSCO - SDC	H	15,731			0.00
SMLP - SDC	J	12,492			0.00
SCM-SDC CASH ADVANCES 267	B	5,184,808			0.00
GH-SDC INTERCO CAPITAL 265	A	1,432,265			0.00
WWOS-SDC			Q	92,907	0.00
CLUB WEST	Z	221,941			0.00
CORAL CANYON	X	655,381			0.00
CC GOLF COURSE TO CC DEVELOPMENT	AA	6,840,673			0.00
RANCHLAND-RANCHO VIEJO	Y	176,174			0.00
INTEREST PAYABLE	P	96,021			818,832.84
S/T NOTES PAYABLE					0.00
$45 MILLION TERM LOAN					0.00
$55 MILLION RLC					0.00
TEXTRON LOAN - PVGC					0.00
DEF PROFIT & UNEARNED REVENUE	E	3,101,379			0.00
PWCC INTERCO PAYABLE					210,445.06
APS LAND INTERCO PAYABLE					0.00

CUSTOMER DEPOSITS					1,690,933.37
		17,736,865		92,907	17,931,349.86
LONG-TERM LIABILITIES					
LONG-TERM NOTES PAYABLE					0.00
WWOS OWES SDC PH I LAND NOTE	P	962,496			0.00
WWOS RLC PAYOFF BY SDC	P	10,000,000			0.00
CORPORATE TERM NOTE					110,000,000.00
CORPORATE RLC					5,215,000.00
LPSCO BONDS					1,332,685.27
TEXTRON LOAN - PVGC					4,830,473.75
LOAN - CLUB WEST					5,415,168.77
PENSION LIABILITY - SUNCOR					310,840.34
PENSION LIABILITY - WIGWAM RESORT					2,526,236.90
OTHER ACCRUED LIABILITIES					17,613.00
DEFERRED TAXES					4,142,445.64
LONG-TERM CUSTOMER DEPOSITS					0.00
CONTRIB PROPERTY AIA					
TOTAL L/T LIABILITIES		10,962,496		0	135,790,463.67
TOTAL LIABILITIES		28,699,361		92,907	153,721,813.53
MINORITY INTEREST	I,Z	10,592,754	I,R,Z	16,222,086	5,629,331.34
SDC COMMON STOCK					1,022,000.00
SDC ADDITIONAL PAID IN CAPITAL					355,368,521.94
SDC EARNED SURPLUS-BEGINNING					(65,374,628.73)
SDC EARNED SURPLUS-CURRENT					11,539,252.10
SUBSIDIARY EARNINGS-CURRENT	D,F,I,S,U,V,T	31,905,521	L,M,R,Q,Y,Z,AA	1,725,482	0.00
SUBSIDIARY EQUITY:					
LPSCO	F,G	15,023,462			0.00
SASI	L	961,291	L	650,000	0.00
SMLP #3500	I	34,407,501	I	30,920,733	0.00
PVGC	M	6,158,173	M	461,618	0.00
CLUB WEST	Z	3,819,026			0.00
HOMEBUILDING	D	2,878,324			0.00
PALM VALLEY #5500	V	132,743,601			(0.00)
KABUTO JV #3000	R	13,729,227			0.00
COMMERCIAL PROPERTIES #2000	S	84,216,204			0.00
HIDDEN HILLS #3300	T	14,460,229			0.00
RANCHO VIEJO #6600	U	16,155,869			0.00
RANCHLAND UTILITY	Y	1,109,212	Y	92,325	(0.00)
CORAL CANYON #3900	W	27,073,924	W	42,620	
TOTAL EQUITY		384,641,564		33,892,778	302,555,145.31
TOTAL LIABS AND EQUITY		423,933,680		50,207,770	461,906,290.18

SUNCOR DEVELOPMENT COMPANY
CONSOLIDATING INCOME STATEMENT
FOR THE YEAR ENDING DECEMBER 31, 2000 (UNAUDITED)

	ACCOUNT DESCRIPTION	SUNCOR	LPSCO	RANCHLAND UTILITY	SCTS MTN
REVENUES					
	Home Sales				
	Land Sales	42,691,399			294,150
	Commercial Properties	8,757,862			
	Utility Sales		3,323,224	65,146	
	Management Fees	845,515			
TOTAL OPERATING REVENUES		52,294,776	3,323,224	65,146	294,150
OPERATING EXPENSES					
	Cost of Homes Sold				
	Cost of Land Sold	17,223,011			250,416
	Commercial Properties	7,886,356			
	Utility Expense		2,292,872	86,505	
	Land Project Costs	1,390,669			18,155
	General & Administrative	11,306,175			59,269
	Depreciation & Amortization	2,103,895	335,546	38,884	
TOTAL OPERATING EXPENSES		39,910,106	2,628,418	125,389	327,840
NET OPERATING INCOME/(LOSS)		12,384,670	694,806	(60,243)	(33,690)
OTHER INCOME AND GAINS					
	Equity in Joint Ventures	2,324,093			
	Interest Income	843,509	223,432		45,877
	Other	1,063,507	3,106		
TOTAL OTHER INCOME AND GAINS		4,231,109	226,537		45,877
INTEREST EXPENSE, NET					
	Interest Expense	8,968,228	307,700		1,780
	Less: Capitalized Interest	(6,201,668)			
TOTAL INTEREST EXPENSE, NET		2,766,560	307,700		1,780
	Minority Interest	(85,715)			575,693
INCOME BEFORE TAXES		13,934,934	613,643	(60,243)	(565,286)
	Income Taxes	7,515,478	248,562		
NET INCOME/(LOSS)		$ 6,419,456	$ 365,081	$ (60,243)	$ (565,286)

	ACCOUNT DESCRIPTION	PVGC	GHH	WWOS	HIDDEN HILLS
REVENUES					
	Home Sales		62,417,638		
	Land Sales		540,000		4,975,000
	Commercial Properties	2,712,685		1,996,347	
	Utility Sales				
	Management Fees				
TOTAL OPERATING REVENUES		2,712,685	62,957,638	1,996,347	4,975,000
OPERATING EXPENSES					
	Cost of Homes Sold		52,467,030		
	Cost of Land Sold		400,379		4,060,531
	Commercial Properties	300,823		846,272	
	Utility Expense				
	Land Project Costs				268,745
	General & Administrative	2,403,103	5,449,460		128,731
	Depreciation & Amortization	575,122	552,175	774,396	
TOTAL OPERATING EXPENSES		3,279,048	58,869,044	1,620,668	4,458,007
NET OPERATING INCOME/(LOSS)		(566,363)	4,088,594	375,679	516,993
OTHER INCOME AND GAINS					
	Equity in Joint Ventures				
	Interest Income			6,244	8,350
	Other		207,146		
TOTAL OTHER INCOME AND GAINS			207,146	6,244	8,350
INTEREST EXPENSE, NET					
	Interest Expense	386,077		1,008,243	
	Less: Capitalized Interest				
TOTAL INTEREST EXPENSE, NET		386,077		1,008,243	
	Minority Interest				
INCOME BEFORE TAXES		(952,440)	4,295,740	(626,320)	525,343
	Income Taxes				
NET INCOME/(LOSS)		$ (952,440)	$ 4,295,740	$ (626,320)	$ 525,343

	ACCOUNT DESCRIPTION	CORAL CANYON	RANCHO VIEJO	CONSOLIDATED INCOME
REVENUES				
	Home Sales	5,438,779	21,822,719	89,679,136
	Land Sales	1,311,125	847,651	50,659,325
	Commercial Properties			13,466,894
	Utility Sales			3,388,370
	Management Fees			845,515
TOTAL OPERATING REVENUES		6,749,904	22,670,370	158,039,240
OPERATING EXPENSES				
	Cost of Homes Sold	4,429,026	17,345,849	74,241,905
	Cost of Land Sold	1,083,259	458,306	23,475,902
	Commercial Properties			9,033,451
	Utility Expense			2,379,377
	Land Project Costs	22,331	241,396	1,941,295
	General & Administrative	1,505,561	1,974,067	22,826,366
	Depreciation & Amortization	31,209	246,078	4,657,305
TOTAL OPERATING EXPENSES		7,071,386	20,265,696	138,555,601
NET OPERATING INCOME/(LOSS)		(321,482)	2,404,674	19,483,639
OTHER INCOME AND GAINS				
	Equity in Joint Ventures			2,324,093
	Interest Income	7,069	371	1,134,851
	Other	16,384	30,903	1,321,046
TOTAL OTHER INCOME AND GAINS		23,453	31,275	4,779,990
INTEREST EXPENSE, NET				
	Interest Expense			10,672,028
	Less: Capitalized Interest			(6,201,668)
TOTAL INTEREST EXPENSE, NET				4,470,360
	Minority Interest			489,978
INCOME BEFORE TAXES		(298,030)	2,435,949	19,303,291
	Income Taxes			7,764,040
NET INCOME/(LOSS)		$ (298,030)	$ 2,435,949	$ 11,539,251

SUNCOR DEVELOPMENT COMPANY
CONSOLIDATING BALANCE SHEET
DECEMBER 2000 CONSOLIDATING & ELIMINATING ENTRIES

			DEBIT	CREDIT
A.	SCM INTERCO A/P TO SDC		$6,881,947.37	
	SDC A/R FROM SCM			$6,881,947.37
	GH INTERCO CAPITAL FROM SDC - ACQUISITION		$1,432,265.22	
	GH INTERCO A/P TO SDC		$1,202,697.24	
	SDC A/R FROM GH			$2,634,962.43
B.	HOMEBUILDING CASH ADVANCES FROM SDC		$5,184,807.73	
	SDC CASH ADVANCES TO HOMEBUILDING			$5,184,807.73
C.	SCM INTERCO CAPPED INTEREST		$5,748,529.44	
	SDC INTERCO INTEREST A/R FROM SCM			$5,748,529.47
	ELIMINATE INTERCO RECEIVABLES/PAYABLES BETWEEN HOMEBUILDING AND SDC			
D.	HOMEBUILDING ACCUMULATED EARNINGS		$2,878,324.34	
	SDC INVESTMENT IN GH			$6,640,235.87
	SDC DUE DILIGENCE COSTS - GHH ACQUISITION			
	SDC INVESTMENT IN SCM			$ 517,849.94
	HOMEBUILDING CURRENT YEAR EARNINGS		$4,279,761.47	
	ELIMINATE SDC INVESTMENT IN GOLDEN HERITAGE & SCM			
E.	DEFERRED INTERCO PROFIT		$3,101,378.61	
	HOME INVENTORY			$3,101,378.61
	ELIMINATE DEFERRED PROFIT ON INTERCO LOT SALES TO HOMEBUILDING			
F.	LPSCO COMMON STOCK	X	78,200.00	
	LPSCO PAID IN CAPITAL		13,128,556.85	
	LPSCO EARNINGS - PRIOR		1,516,705.00	
	LPSCO EARNINGS - CURRENT YEAR		365,081.67	
	SDC INVESTMENT IN LPSCO - CONTRIB CAPITAL			13,206,756.86
	SDC INVESTMENT IN LPSCO - EARNINGS			1,881,048.20
	SDC DEFERRED TAXES DIFFERENTIAL			
	ELIMINATE SDC INVESTMENT IN LPSCO			
G.	LPSCO LONG-TERM NOTES PAYABLE	X	300,000.00	
	SDC LONG-TERM NOTES RECEIVABLE			300,000.00
	ELIMINATE LPSCO INTERCOMPANY NOTE WITH SDC			
H.	LPSCO ACCOUNTS PAYABLE		15,730.51	
	SDC ACCOUNTS RECEIVABLE			15,730.51
	ELIMINATE LPSCO INTERCOMPANY A/R WITH SDC			
I.	SMLP CONTRIBUTED CAPITAL - MINORITY INT	X		10,507,040.00
	SMLP CONTRIBUTED CAPITAL - SDC GP		490,147.01	
	SMLP DISTRIBUTED CAPITAL - SDC GP			13,483,361.00
	SMLP CONTRIBUTED CAPITAL - SDC LP		2,100,000.00	
	SMLP DISTRIBUTED CAPITAL - SDC LP			6,930,332.00
	SMLP EARNINGS - PRIOR		31,817,353.69	
	SMLP EARNINGS - CURRENT YEAR		45,973.27	
	MINORITY INTEREST CONTRIBUTED CAPITAL		10,507,040.00	
	MINORITY INTEREST - PRIOR (35%)			11,710,226.79
	MINORITY INTEREST - CURRENT YEAR (35%)			16,090.64
	SDC INVESTMENT IN SMLP - LP			2,100,000.00
	SDC DISTRIBUTIONS FROM SMLP - LP		6,955,259.26	
	SDC INVESTMENT IN SMLP - GP			490,147.01
	SDC DISTRIBUTIONS FROM SMLP - GP		13,458,433.74	
	SDC INVESTMENT IN SMLP - EARNINGS			20,137,009.52
	SDC LAND BASIS DIFFERENTIAL			
	ELIMINATE SDC INVESTMENT IN SMLP #3500			
J.	SMLP ACCOUNTS PAYABLE	X	12,491.79	
	SDC ACCOUNTS RECEIVABLE			12,491.79

SUNCOR DEVELOPMENT COMPANY
CONSOLIDATING BALANCE SHEET
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			DEBIT	CREDIT
	ELIMINATE SMLP INTERCOMPANY A/R WITH SDC AND HOMEBUILDING (PREMIUMS)			
L.	SASI CONTRIBUTED CAPITAL	X	489,023.22	
	SASI CAPITAL DISTRIBUTIONS			650,000.00
	SASI EARNINGS - PRIOR YEARS		472,267.95	
	SASI EARNINGS - CURRENT YEAR			76,048.00
	PV INVESTMENT IN SASI - CONTRIB CAPITAL			489,023.22
	PV INVESTMENT IN SASI - DISTRIBUTIONS		650,000.00	
	PV INVESTMENT IN SASI - EARNINGS			396,219.95
	ELIMINATE PALM VALLEY INVESTMENT IN SASI			
M.	PVGC BOOKS - SDC CONTRIBUTED CAPITAL	X	6,158,173.14	
	PVGC EARNINGS - PRIOR YEARS			461,617.51
	PVGC EARNINGS - CURRENT			952,440.16
	SDC INVESTMENT IN PVGC - EARNINGS		1,414,057.67	
	SDC INVESTMENT IN PVGC - CONTRIB CAPITAL			6,158,173.14
	ELIMINATE SDC INVESTMENT IN PALM VALLEY GOLF			
N.	SDC CONTRIB. CAPITAL TO PVGC	X		4,940,770.42
	PVGC ACCOUNTS RECEIVABLE		4,940,770.42	
O.	INTENTIONALLY LEFT BLANK.			
P.	WWOS INTEREST PAYABLE - RLC	X	96,097.45	
	SDC INTEREST RECEIVABLE - PHASE 1 LAND			21,834.16
	SDC INTEREST RECEIVABLE - RLC			74,263.29
	WWOS NOTES PAYABLE - PHASE 1 LAND		962,496.44	
	SDC NOTES RECEIVABLE - PHASE 1 LAND			962,496.44
	WWOS NOTES PAYABLE - RLC	X	10,000,000.00	
	SDC NOTES RECEIVABLE - RLC			10,000,000.00
	ELIMINATE WWOS INTERCOMPANY NOTES AND INTEREST WITH SDC			
Q.	WWOS ACCOUNTS PAYABLE	X	92,906.63	
	SDC ACCOUNTS RECEIVABLE			92,906.63
	ELIMINATE WWOS INTERCOMPANY A/R WITH SDC			
R.	KABUTO CONTRIBUTED CAPITAL - SDC	X	9,610,458.25	
	KABUTO CONTRIBUTED CAPITAL - KABUTO		4,118,768.30	
	KABUTO CURRENT PERIOD EARNINGS			1,918.95
	MINORITY INTEREST			4,118,768.30
	SDC INVESTMENT IN KABUTO - CONTR CAPITAL			9,610,458.25
	SDC INVESTMENT IN KABUTO - EARNINGS		1,918.95	
	ELIMINATE SDC INVESTMENT IN KABUTO JV #3000			
S.	COMMERCIAL OPS CONTRIBUTED CAPITAL	X	74,021,688.26	
	COMMERCIAL EARNINGS - PRIOR		10,194,516.13	
	COMMERCIAL EARNINGS - CURRENT YEAR		4,796,650.73	
	SDC INVEST IN GEN COMMERCIAL OPS - EARNINGS			4,222,681.73
	SDC INVEST IN GEN COMMERCIAL OPS - CONT CAPITAL			75,133,507.87
	SDC INVEST IN HAYDEN FERRY LAKESIDE			3,013,509.35
	SDC INVESTMENT IN OUTER LIMITS - PURCHASE			1,822,514.94
	SDC INVESTMENT IN FIDDLE (SCOTTS) - CONT CAPITAL		3,761,778.75	
	SDC INVESTMENT IN FIDDLE (SCOTTS) - EARNINGS		632,086.48	
	SDC INVESTMENT IN FUNTASTICKS - CONT CAPITAL		475,281.57	
	SDC INVESTMENT IN FUNTASTICKS - EARNINGS			621,866.50
	SDC INVESTMENT IN FIDDLE (TEMPE) - CONT CAPITAL		1,708,971.07	
	SDC INVESTMENT IN FIDDLE (TEMPE) - EARNINGS			1,304,459.03
	SDC INVESTMENT IN APS PROPERTIES - EARNINGS			422,039.77
	SDC INVESTMENT IN BLACK CANYON CP - EARNINGS			741,505.80
	SDC INVESTMENT IN PV MARKETPLACE - EARNINGS			3,473,608.17
	SDC INVESTMENT IN PV PAVILIONS - EARNINGS			3,821,321.75

SUNCOR DEVELOPMENT COMPANY
CONSOLIDATING BALANCE SHEET
DECEMBER 2000 CONSOLIDATING & ELIMINATING ENTRIES

			DEBIT	CREDIT
	SDC INVESTMENT IN DYSART/MCDOWELL CENTER			872,111.61
	SDC INVESTMENT IN PV CROSSING			1,306,478.79
	SDC INVESTMENT IN PV OFFICE PARK			247,225.04
	SDC INVESTMENT IN METROCENTER			281,410.66
	SDC INVESTMENT IN RESTORATION PALACE		178,046.92	
	SDC INVESTMENT IN LITCHFIELD PARK OPS			168,239.27
	SDC INVESTMENT IN AUTOPLEX		148,809.37	
	SDC INVESTMENT IN TALAVI - EARNINGS		221,422.43	
	SDC INVESTMENT IN WWOS - EARNINGS		1,319,039.52	
	SDC INVESTMENT IN LP PROF. PLAZA - EARNINGS			6,875.56
	ELIMINATE SDC INVESTMENT IN COMMERCIAL OPERATIONS #2000			
T.	HIDDEN HILLS SDC CONTRIBUTED CAPITAL	X	9,898,479.18	
	GLAZ CONTRIBUTED CAPITAL, NET		4,474,530.28	
	GLAZ INVESTMENT IN HIDDEN HILLS - CONT CAPITAL			4,474,530.28
	HIDDEN HILLS EARNINGS - PRIOR		87,219.79	
	HIDDEN HILLS EARNINGS - CURRENT YEAR		1,396,891.01	
	SDC INVESTMENT IN HIDDEN HILLS - EARNINGS			1,484,110.80
	SDC INVESTMENT IN HIDDEN HILLS - CONT CAPITAL			9,898,478.90
	ELIMINATE SDC INVESTMENT IN HIDDEN HILLS JV #3300			
U.	SDC INVESTMENT IN RANCHO VIEJO - EARNINGS	X		3,936,793.89
	SDC INVESTMENT IN RANCHO VIEJO - CAPITAL			14,826,853.90
	RANCHO VIEJO CONTRIBUTED CAPITAL		14,826,853.90	
	RANCHO VIEJO EARNINGS - PRIOR		1,329,014.88	
	RANCHO VIEJO EARNINGS - CURRENT YEAR		2,607,778.40	
	ELIMINATE SDC INVESTMENT IN RANCHO VIEJO JV #6600			
V.	PV CONTRIBUTED CAPITAL	X	118,191,627.22	
	PV EARNINGS - PRIOR		14,551,973.51	
	PV EARNINGS - CURRENT YEAR		18,413,384.22	
	SDC INVESTMENT IN PALM VALLEY - EARNINGS			32,965,357.73
	SDC INVESTMENT IN PALM VALLEY - DEVELOP			118,191,627.22
	ELIMINATE SDC INVESTMENT IN PALM VALLEY #5500			
W.	CORAL CANYON CONTRIBUTED CAPITAL		27,073,924.12	
	CORAL CANYON - PRIOR			42,620.30
	CORAL CANYON - CURRENT YEAR			156,726.00
	SDC INVESTMENT IN CORAL CANYON - DEVELOP			27,073,923.10
	SDC INVESTMENT IN CORAL CANYON - EARNINGS		199,345.28	
X.	CORAL CANYON ACCOUNTS PAYABLE		655,380.98	
	CORAL CANYON INTERCOMPANY INVOICES			5,708.26
	SDC ACCOUNTS RECEIVABLE			650,044.04
	ELIMINATE SDC INVESTMENT IN CORAL CANYON #3900			
Y.	RANCHLAND - CURRENT YEAR			60,243.14
	RANCHLAND - PRIOR YEARS EARNINGS			92,325.37
	RANCHLAND - CONTRIBUTED CAPITAL		1,109,211.60	
	RANCHLAND - DUE TO/FROM RANCHO VIEJO		176,174.00	
	RANCHO INVESTMENT IN RANCHLAND UTILTY-CAPITAL			1,109,211.60
	SDC INVESTMENT IN RL UTILTY-EARNINGS PRIOR		92,325.37	
	SDC INVESTMENT IN RL UTILTY-EARNINGS CURRENT		59,775.62	
	RANCHO - DUE TO/FROM RANCHLAND UTILITIES			177,219.76
	ELIMINATE RANCHO INVESTMENT IN RANCHLAND UTILITY			
Z.	CLUB WEST - MINORITY INTEREST		377,000.00	
	CLUB WEST - SDC CONTRIBUTED CAPITAL		3,442,026.39	
	CLUB WEST - CURRENT YEAR EARNINGS			267,857.48
	CLUB WEST - PRIOR EARNINGS			
	CLUB WEST - INTERCOMPANY WITH SDC		221,941.29	
	MINORITY INTEREST-32%		85,714.39	
	SDC INVESTMENT - EARNINGS		182,143.09	
	SDC INVESTMENT - CAPITAL			3,442,026.39
	CWGC CONTRIBUTED CAPITAL - MINORITY INT			377,000.00
	SDC INTERCOMPANY WITH CLUB WEST			221,941.29

SUNCOR DEVELOPMENT COMPANY
CONSOLIDATING BALANCE SHEET
DECEMBER 2000 CONSOLIDATING & ELIMINATING ENTRIES

		DEBIT	CREDIT
	ELIMINATE SDC INVESTMENT IN CLUB WEST		
AA	CORAL CANYON GOLF - CURRENT YEAR EARNINGS		210,248.19
	CORAL CANYON GOLF COURSE - INTERCOMPANY WITH CORAL CANYON DEVELOPMENT	6,840,673.36	
	CORAL CANYON DEVELOPMENT - INTERCOMPANY WITH CORAL CANYON GOLF COURSE		6,840,673.00
		54,809.40	
			54,809.40
	SDC INVESTMENT EARNINGS	208,745.93	
	ELIMINATE SDC INVESTMENT IN CORAL CANYON GOLF CLUB		

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Company: PINNACLE WEST CAPITAL CORP
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Adopted November 9, 1939 File No. 69-306

SECURITIES AND EXCHANGE COMMISSION
Washington, D.C.

FORM U-3A-2

STATEMENT BY HOLDING COMPANY
CLAIMING EXEMPTION UNDER RULE U-3A-2
FROM THE PROVISIONS OF THE
PUBLIC UTILITY HOLDING COMPANY ACT OF 1935

To Be Filed Annually Prior to March 1

Pinnacle West Capital Corporation

(Name of Company)

hereby files with the Securities and Exchange Commission, pursuant to Rule 2, its statement claiming exemption as a holding company from the provisions of the Public Utility Holding Company Act of 1935, and submits the following information:

1. NAME, STATE OF ORGANIZATION, LOCATION AND NATURE OF BUSINESS OF CLAIMANT AND EVERY SUBSIDIARY THEREOF, OTHER THAN ANY EXEMPT WHOLESALE GENERATOR (EWG) OR FOREIGN UTILITY COMPANY IN WHICH CLAIMANT DIRECTLY OR INDIRECTLY HOLDS AN INTEREST.

Pinnacle West Capital Corporation ("Claimant"), having been incorporated on February 20, 1985 under the laws of the State of Arizona, and having its principal executive offices at 400 East Van Buren, Suite 700, Phoenix, Arizona 85004, was organized principally to acquire and hold securities of other corporations for investment purposes. The following are the subsidiaries of the Claimant:

a. Arizona Public Service Company ("APS" or the "Company"), is engaged principally in serving electricity in the State of Arizona. Incorporated in 1920 under the laws of the State of Arizona and having its principal executive offices at 400 North Fifth Street, Phoenix, Arizona 85004, APS became a subsidiary of the Claimant pursuant to a corporate restructuring plan approved by the Company's shareholders on April 18, 1985.

(1) AXIOM Power Solutions, Inc. ("AXIOM") -- an Arizona corporation having been incorporated on October 29, 1996 and having its principal executive offices at 400 E. Van Buren, Phoenix, Arizona 85004, was organized primarily to sell security and energy management products and services. AXIOM is a wholly-owned subsidiary of APS.

(2) Bixco, Inc. ("Bixco") -- an Arizona corporation having been incorporated on June 4, 1971 and having its principal executive offices at 400 North Fifth Street, Phoenix, Arizona 85004, was organized primarily to conduct exploration activities for energy resources and other valuable minerals. Subsequent to the sale of its oil and natural gas properties in 1981, Bixco has been inactive. Bixco is a wholly-owned subsidiary of APS.

b. APS Energy Services Company, Inc. ("APSES") -- an Arizona corporation having been incorporated on November 6, 1998 and having its principal executive offices at 400 E. Van Buren, Phoenix, Arizona 85004, was organized primarily to sell energy, products and services. APSES is a wholly-owned subsidiary of the Claimant.

c. SunCor Development Company ("SunCor") - an Arizona corporation having been incorporated on June 30, 1965 and having its

principal executive offices at 3838 North Central Avenue, Suite 1500, Phoenix, Arizona 85012, is a wholly-owned subsidiary of Claimant engaged primarily in the owning, holding and development of real property.

(1) SunCor Resort & Golf Management, Inc. ("Resort & Golf Management") (previously named "SunCor Resort Management, Inc." and "SunCor Farms, Inc.") -- an Arizona corporation having been incorporated on December 31, 1986 and having its principal executive offices at 3838 North Central Avenue, Suite 1500, Phoenix, Arizona 85012, operates and manages hotel, golf, food and beverage for the Wigwam Resort and Country Club, Sedona Golf Resort, SunRidge Canyon Golf Club, Sanctuary Gold Club at West World and Palm Valley Golf Club. Resort & Golf Management is a wholly-owned subsidiary of SunCor.

(2) Litchfield Park Service Company ("LPSCO") -- an Arizona corporation having been incorporated on September 21, 1954 and having its principal executive offices at 111 West Wigwam Boulevard, Suite B, Litchfield Park, Arizona 85340, is a regulated public utility engaged in providing water and sewer services to commercial and residential customers. LPSCO became a wholly-owned subsidiary of SunCor on December 31,1986.

(3) Golden Heritage Homes, Inc. ("Golden Heritage Homes") -- (previously named "SunCor Homes, Inc.", "LGR, Inc." and "WGP Realty, Inc.") an Arizona corporation having been incorporated on May 14, 1986 and having its principal executive offices at 7025 East Greenway Parkway, Suite 100, Scottsdale, Arizona 85254, was organized to provide brokerage and realty services in the sale of commercial and residential real property. Golden Heritage Homes is a wholly-owned subsidiary of SunCor.

(i) Golden Heritage Construction, Inc. ("GH Construction") -- an Arizona corporation having been incorporated on December 30, 1993 and having its principal executive offices at 3838 North Central Avenue, Suite 1500, Phoenix, Arizona 85012, was organized to serve as a general residential contractor. GH Construction became a wholly-owned

subsidiary of Golden Heritage Homes, Inc. on January 1, 1996.

(4) SCM, Inc. ("SCM") -- an Arizona corporation having been incorporated on May 14, 1991 and having its principal executive offices at 3838 North Central Avenue, Suite 1500, Phoenix, Arizona 85012, was organized to participate in real estate joint ventures and other real estate related activities. SCM is a wholly-owned subsidiary of SunCor.

(5) Golf de Mexico, S.A. DE C.V. ("Golf de Mexico") -- a Mexican variable capital corporation having been incorporated on February 8, 1992 in Tijuana, Baja California, Mexico, and having its principal executive offices at 3838 North Central Avenue, Suite 1500, Phoenix, Arizona 85012, was organized to operate and manage the Real del Mar Golf Course in Mexico. Golf de Mexico has been inactive since 1997.

(6) SunCor Realty & Management Company ("SunCor Realty") -- (previously named Russell Ranch Development Company) an Arizona corporation having been incorporated on April 1, 1994 and having its principal executive offices at 3838 North Central Avenue, Suite 1500, Phoenix, Arizona 85012 was organized to participate in real estate management and other real estate related activities. SunCor Realty is a wholly-owned subsidiary of SunCor.

(7) Palm Valley Golf Club, Inc. ("Palm Valley Golf") -- an Arizona corporation having been incorporated on January 23, 1996 and having its principal executive offices at 3838 North Central Avenue, Suite 1500, Phoenix, Arizona 85012, was organized to hold title to the Palm Valley Golf Course. Palm Valley Golf is a wholly-owned subsidiary of SunCor.

(8) Rancho Viejo de Santa Fe, Inc. ("Rancho Viejo") -- a New Mexico corporation having been incorporated on March 18, 1996 and having its principal executive offices at 1590-B Pacheco Street, Santa Fe, New Mexico 87505, was organized to engage in real estate development in New Mexico. Rancho Viego is a wholly-owned subsidiary of SunCor.

(9) Ranchland Utility Company ("Ranchland") -- a New Mexico corporation having been incorporated on September 5, 1997 and having its principal executive offices at 1590-B Pacheco Street, Santa Fe, New Mexico 87505 is a waste water utility. Ranchland is a wholly-owned subsidiary of Rancho Viejo.

d. El Dorado Investment Company -- an Arizona corporation having been incorporated on July 27, 1983 and having its principal executive offices at 400 East Van Buren, Suite 800, Phoenix, Arizona 85004, is a wholly-owned subsidiary of Claimant engaged primarily in the acquisition and holding of stocks and securities of other companies for investment purposes.

e. Pinnacle West Energy Corporation ("PWEC") - an Arizona corporation having been incorporated on September 27, 1999, and having its principal executive offices at 400 North Fifth Street, Phoenix, Arizona 85004, was organized primarily for the development, production and sale of wholesale energy. PWEC is a wholly-owned subsidiary of the Claimant.

2. A BRIEF DESCRIPTION OF THE PROPERTIES OF CLAIMANT AND EACH OF ITS SUBSIDIARY PUBLIC UTILITY COMPANIES USED FOR THE GENERATION, TRANSMISSION AND DISTRIBUTION OF ELECTRIC ENERGY FOR SALE, OR FOR THE PRODUCTION, TRANSMISSION AND DISTRIBUTION OF NATURAL OR MANUFACTURED GAS, INDICATING THE LOCATION OF PRINCIPAL GENERATING PLANTS, TRANSMISSION LINES, PRODUCING FIELDS, GAS MANUFACTURING PLANTS AND ELECTRIC AND GAS DISTRIBUTION FACILITIES, INCLUDING ALL SUCH PROPERTIES WHICH ARE OUTSIDE THE STATE IN WHICH CLAIMANT AND ITS SUBSIDIARIES ARE ORGANIZED AND ALL TRANSMISSION OR PIPELINES WHICH DELIVER OR RECEIVE ELECTRIC ENERGY OR GAS AT THE BORDERS OF SUCH STATE.

Neither the Claimant nor any of its subsidiaries own property used for the production, transmission and distribution of natural or manufactured gas. APS, a "public utility company" as that term is defined in the Public Utility Holding Company Act of 1935, is the only one of Claimant's subsidiaries that owns property used for the generation, transmission and distribution of electric energy for sale.

Exhibit D attached hereto shows the location of APS' major generating plants (including those owned jointly with others), principal transmission lines (including those operated for others) and interconnections of transmission lines with out-of-state utilities at state lines. All of such facilities, except the Four Corners Generating Station ("Four Corners"), and all of APS' distribution facilities, are located within the State of Arizona. Four Corners is a mine-mouth power plant, located in the northwest corner of New Mexico, near the city of Farmington, approximately 40 miles east of the Arizona-New Mexico border.

APS' present generating facilities have an accredited capacity aggregating 3,986,900 kilowatts, comprised as follows:

	Capacity (kW)
Coal:	
Units 1, 2 and 3 at Four Corners, aggregating	560,000
15% owned Units 4 and 5 at Four Corners, representing	222,000
Units 1, 2, and 3 at the Cholla Plant, aggregating	615,000
14% owned Units 1, 2 and 3 at the Navajo Plant, representing	315,000
	1,712,000
Gas or Oil:	
Two steam units at Ocotillo and two steam units at Saguaro, aggregating	435,000(1)
Eleven combustion turbine units, aggregating	493,000
Three combined cycle units, aggregating	255,000
	1,183,000
Nuclear:	
29.1 % owned or leased Units 1, 2 and 3 at Palo Verde, representing	1,086,300
Other	5,600

(1) West Phoenix steam units (108,300 kw) are currently mothballed.

APS' transmission facilities consist of approximately 5,273 pole miles of overhead lines and approximately 23 miles of underground lines, all of which are located within the State of Arizona. APS' distribution facilities consist of approximately 11,541 pole miles of overhead lines and approximately 10,711 miles of underground lines, all of which are located within the State of Arizona.

3. THE FOLLOWING INFORMATION FOR THE LAST CALENDAR YEAR WITH RESPECT TO CLAIMANT AND EACH OF ITS SUBSIDIARY PUBLIC UTILITY COMPANIES:

(DATA IS NOT MAINTAINED IN A FORMAT IDENTIFYING THE STATE IN WHICH THE SALES AND PURCHASES ARE MADE OR THE AMOUNT OF THEIR ASSOCIATED REVENUES OR EXPENSES.)

a. NUMBER OF KWH OF ELECTRIC ENERGY SOLD (AT RETAIL OR WHOLESALE), AND MCF. OF NATURAL OR MANUFACTURED GAS DISTRIBUTED AT RETAIL.

36,768,404,000 kwh of electric energy sold at wholesale or retail

0 Mcf. of natural or manufactured gas distributed at wholesale or retail

b. NUMBER OF KWH OF ELECTRIC ENERGY AND MCF. OF NATURAL OR MANUFACTURED GAS DISTRIBUTED AT RETAIL OUTSIDE THE STATE IN WHICH EACH SUCH COMPANY IS ORGANIZED.

73,792,000 kwh of electric energy was distributed at retail outside Arizona

0 Mcf. of natural or manufactured gas distributed at retail outside Arizona

c. NUMBER OF KWH OF ELECTRIC ENERGY AND MCF. OF NATURAL OR MANUFACTURED GAS SOLD AT WHOLESALE OUTSIDE THE STATE IN WHICH EACH SUCH COMPANY IS ORGANIZED, OR AT THE STATE LINE.

964,100 kwh of electric energy was sold at wholesale outside Arizona or at state line (excluding power marketing activities).

0 Mcf. of natural or manufactured gas sold at wholesale outside Arizona or at state line (excluding power marketing activities).

d. NUMBER OF KWH OF ELECTRIC ENERGY AND MCF. OF NATURAL OR MANUFACTURED GAS PURCHASED OUTSIDE THE STATE IN WHICH EACH SUCH COMPANY IS ORGANIZED OR AT THE STATE LINE.

1,337,740,000 kwh of electric energy was purchased outside Arizona or at state line (excluding power marketing activities).

23,829,168 Mcf. of natural or manufactured gas purchased outside Arizona or at state line (excluding power marketing activities).

4. THE FOLLOWING INFORMATION FOR THE REPORTING PERIOD WITH RESPECT TO CLAIMANT AND EACH INTEREST IT HOLDS DIRECTLY OR INDIRECTLY IN AN EWG OR A FOREIGN UTILITY COMPANY, STATING MONETARY AMOUNTS IN UNITED STATES DOLLARS:

The Claimant holds no interest, direct or indirect, in an EWG or a foreign utility company.

a. NAME, LOCATION, BUSINESS ADDRESS AND DESCRIPTION OF THE FACILITIES USED BY THE EWG OR FOREIGN UTILITY COMPANY FOR THE GENERATION, TRANSMISSION AND DISTRIBUTION OF ELECTRIC ENERGY FOR SALE OR FOR THE DISTRIBUTION AT RETAIL OF NATURAL OR MANUFACTURED GAS.

Not applicable.

b. NAME OF EACH SYSTEM COMPANY THAT HOLDS AN INTEREST IN SUCH EWG OR FOREIGN UTILITY COMPANY; AND DESCRIPTION OF THE INTEREST HELD.

Not applicable.

c. TYPE AND AMOUNT OF CAPITAL INVESTED, DIRECTLY OR INDIRECTLY, BY THE HOLDING COMPANY CLAIMING EXEMPTION; ANY DIRECT OR INDIRECT GUARANTEE

OF THE SECURITY OF THE EWG OR FOREIGN UTILITY COMPANY BY THE HOLDING COMPANY CLAIMING EXEMPTION; AND ANY DEBT OR OTHER FINANCIAL OBLIGATION FOR WHICH THERE IS RECOURSE, DIRECTLY OR INDIRECTLY, TO THE HOLDING COMPANY CLAIMING EXEMPTION OR ANOTHER SYSTEM COMPANY, OTHER THAN THE EWG OR FOREIGN UTILITY COMPANY.

Not applicable.

d. CAPITALIZATION AND EARNINGS OF THE EWG OR FOREIGN UTILITY COMPANY DURING THE REPORTING PERIOD.

Not applicable.

e. IDENTIFY ANY SERVICE, SALES OR CONSTRUCTION CONTRACT(S) BETWEEN THE EWG OR FOREIGN UTILITY COMPANY AND A SYSTEM COMPANY, AND DESCRIBE THE SERVICES TO BE RENDERED OR GOODS SOLD AND FEES OR REVENUES UNDER SUCH AGREEMENT(S).

Not applicable.

EXHIBIT A

A CONSOLIDATING STATEMENT OF INCOME AND SURPLUS OF THE CLAIMANT AND ITS SUBSIDIARY COMPANIES FOR THE LAST CALENDAR YEAR, TOGETHER WITH A CONSOLIDATING BALANCE SHEET OF CLAIMANT AND ITS SUBSIDIARY COMPANIES AS OF THE CLOSE OF SUCH CALENDAR YEAR.

Exhibit A hereto includes consolidating statements of income and consolidating balance sheets for the Claimant and the following of its subsidiaries: Arizona Public Service Company, SunCor Development Company, El Dorado Investment Company, and APS Energy Services Company, Inc. Subsidiaries have been consolidated for financial reporting purposes in accordance with Statement of Financial Accounting Standards No. 94, Consolidation of All Majority-Owned Subsidiaries. Also included are consolidating statements of income and consolidating balance sheets for SunCor Development Company and its subsidiaries.

EXHIBIT B FINANCIAL DATA STATEMENT

IF, AT THE TIME A REPORT ON THIS FORM IS FILED, THE REGISTRANT IS REQUIRED TO SUBMIT THIS REPORT AND ANY AMENDMENTS THERETO ELECTRONICALLY VIA EDGAR, THE REGISTRANT SHALL FURNISH A FINANCIAL DATA SCHEDULE. THE SCHEDULE SHALL SET FORTH THE FINANCIAL AND OTHER DATA SPECIFIED BELOW THAT ARE APPLICABLE TO THE REGISTRANT ON A CONSOLIDATED BASIS.

1. TOTAL ASSETS.

2. TOTAL OPERATING REVENUES.

3. NET INCOME.

See Exhibit B hereto.

EXHIBIT C

AN ORGANIZATIONAL CHART SHOWING THE RELATIONSHIP OF EACH EWG OR FOREIGN UTILITY COMPANY TO ASSOCIATE COMPANIES IN THE HOLDING-COMPANY SYSTEM.

Not applicable.

EXHIBIT D

In accordance with Item 304 of Regulation S-T of the Securities Exchange Act of 1934, APS' Service Territory map contained as Exhibit D to this Form U-3A-2 is a map of the State of Arizona showing APS' service area, the location of its major power plants and principal transmission lines, and the location of transmission lines operated by APS for others. The major power plants shown on such map are the Navajo Generating Station located in Coconino County, Arizona; the Four Corners Power Plant located near Farmington, New Mexico; the Cholla Power Plant, located in Navajo County, Arizona; the Yucca Power Plant, located near Yuma, Arizona; and the Palo Verde Nuclear Generating Station, located about 55 miles west of Phoenix, Arizona (each of which plants is reflected on such map as being jointly owned with other utilities), as well as the Ocotillo Power Plant and West Phoenix Power Plant, each located near Phoenix, Arizona, and the Saguaro Power Plant, located near Tucson, Arizona. APS' major transmission lines shown on such map are reflected as running between the power plants named above and certain major cities in the State of Arizona. The transmission lines operated for others shown on such map are reflected as running from the Four Corners Plant through a portion of northern Arizona to the California border.

The above-named Claimant has caused this statement to be duly executed on its behalf by its authorized officer on this 29th day of February, 2000.

Pinnacle West Capital corporation

(Name of Claimant)

By Barbara M. Gomez

Barbara M. Gomez
Treasurer

[CORPORATE SEAL]

Attest:

Suzanne Debes

Suzanne Debes
Associate Secretary

Name, title and address of officer to whom notices and correspondence concerning this statement should be addressed:

Barbara M. Gomez	Treasurer
(Name)	(Title)

400 North Fifth Street, Station 9996, Phoenix, Arizona 85004

(Address)

PINNACLE WEST CAPITAL CORPORATION
EXHIBIT B
FINANCIAL DATA SCHEDULE
HOLDING COMPANY REPORT
12/31/99

The Claimant submits the following consolidated financial information:

1	Total Assets:	$6,608,506,000
2	Total Operating Revenues:	$2,423,353,000
3	Net Income:	$ 167,887,000

PINNACLE WEST CAPITAL CORPORATION
CONSOLIDATING BALANCE SHEET (UNAUDITED)
DECEMBER 31, 1999
(THOUSANDS OF DOLLARS)

	PWCC	APS	SUNCOR	ELDO
ASSETS				
CURRENT ASSETS				
Cash and cash equivalents	$ 2,057	$ 7,477	$ 7,900	$ 2,863
Customer and other receivables - net	496	235,851	7,277	2,746
Accrued utility revenue		72,919		
Materials and supplies		69,977		
Fossil fuel		21,869		
Deferred income taxes	0	8,163	8,000	0
Other current assets	290	30,885	30,118	0
Total current assets	2,843	447,141	53,295	5,609
INVESTMENTS AND OTHER ASSETS				
Real estate investments, net (cap interest) 1145.1			343,747	
Other assets	2,349,257	208,457	9,020	31,006
Total investments and other	2,349,257	208,457	352,767	31,006
PROPERTY, PLANT AND EQUIPMENT				
plant in service		7,545,575		
Nuclear Fuel		49,114		
Construction work in progress	20,273	184,763		
Total	20,273	7,779,452		
Less accumulated depreciation and amortization		3,026,041		
Net Property, Plant and Equipment	20,273	4,753,411		
DEFERRED DEBITS				
Deferred income taxes			25,257	
Regulatory assets		613,729		
Other deferred debits	1,009	94,886	10,826	0
Total deferred debits	1,009	708,615	36,083	0
TOTAL ASSETS	$2,373,382	$6,117,624	$ 442,145	$ 36,615

	ENERGY SERVICES	*ELIMINATIONS AND ADJUSTING ENTRIES* DEBIT	CREDIT	TOTAL
ASSETS				
CURRENT ASSETS				
Cash and cash equivalents	$ 408			$ 20,705
Customer and other receivables - net	133	--(n)	1,904 (b,d,l,p,q)	244,599
Accrued utility revenue				72,919
Materials and supplies				69,977
Fossil fuel				21,869
Deferred income taxes			8,000 (o)	8,163
Other current assets			731 (c)	60,562
Total current assets	541	0	10,635	498,794
INVESTMENTS AND OTHER ASSETS				
Real estate investments, net (cap interest) 1145.1		5,450(f)	4,904 (e)	344,293
Other assets			2,330,282 (a,f,h,m,n)	267,458
Total investments and other	0	5,450	2,335,186	611,751
PROPERTY, PLANT AND EQUIPMENT				
plant in service	739			7,546,314
Nuclear Fuel				49,114
Construction work in progress	4,245			209,281
Total	4,984			7,804,709
Less accumulated depreciation and amortization	153			3,026,194
Net Property, Plant and Equipment	4,831			4,778,515
DEFERRED DEBITS				
Deferred income taxes			25,257 (o)	--
Regulatory assets				613,729
Other deferred debits		5(h)	1,009 (j)	105,717
Total deferred debits	0	5	26,266	719,446
TOTAL ASSETS	$ 5,372	$ 5,455	$2,372,087	$6,608,506

PINNACLE WEST CAPITAL CORPORATION
CONSOLIDATING BALANCE SHEET
December 31, 1999
(THOUSANDS OF DOLLARS)

	PWCC	APS	SUNCOR	ELDO
LIABILITIES AND EQUITY				
CURRENT LIABILITIES				
Accounts payable	$ 2,409	$ 170,663	$ 11,200	$ 88
Accrued taxes		62,858		8
Accrued interest	277	32,299	677	
Dividend payable	--	--		
Short-term borrowings	--	--		
Commerical paper, net	--	38,300		
Current maturities of long-term debt		114,711	87	
Deferred fuel				
Customer Deposits		24,682	1,416	
Other current liabilities	3,839	26,248	1,292	361
Total current liabilities	6,525	469,761	14,672	457
NON-CURRENT LIABILITIES				
Long-term debt less current maturities	106,000	1,997,400	102,652	
Total	106,000	1,997,400	102,652	--
DEFERRED CREDITS AND OTHER				
Deferred income taxes	38,865	1,178,085		7,774
Deferred investment tax credit 2123.1		4,839		
Unamortized gain-sale of utility plant		73,212		
Other deferred credits	16,259	411,154	8,901	
Total deferred credits	55,124	1,667,290	8,901	7,774
COMMITMENTS AND CONTINGENCIES (NOTE)				
MINORITY INTERESTS:				
Joint Ventures of SunCor			4,904	
COMMON STOCK EQUITY:				
Common stock	2,010,550	1,424,966	376,391	28,046
Accumulated deficit	195,183	558,207	(65,375)	338
Total	2,205,733	1,983,173	311,016	28,384
TOTAL LIABILITIES AND EQUITY	$2,373,382	$6,117,624	$ 442,145	$ 36,615

	ENERGY SERVICES	*ELIMINATIONS* DEBIT		CREDIT		TOTAL
LIABILITIES AND EQUITY						
CURRENT LIABILITIES						
Accounts payable	$ 3,118	$ 954	(l,p)			$ 186,524
Accrued taxes		(7,612)	(k)	32	(k,i)	70,510
Accrued interest						33,253
Dividend payable			(d)			0
Short-term borrowings			(m)			0
Commerical paper, net						38,300
Current maturities of long-term debt						114,798
Deferred fuel						0
Customer Deposits						26,098
Other current liabilities		5,733	(b,c,g,l,q)			26,007
Total current liabilities	3,118	(925)		32		495,490
NON-CURRENT LIABILITIES						
Long-term debt less current maturities						2,206,052
Total		--		--		2,206,052
DEFERRED CREDITS AND OTHER						
Deferred income taxes			(k)	(40,869)	(k,o)	1,183,855
Deferred investment tax credit 2123.1		1,009	(j)			3,830
Unamortized gain-sale of utility plant						73,212
Other deferred credits				4,020	(g)	440,334
Total deferred credits		1,009		(36,849)		1,701,231
COMMITMENTS AND CONTINGENCIES (NOTE)						
MINORITY INTERESTS:						
Joint Ventures of SunCor		4,904	(e)			0
COMMON STOCK EQUITY:						
Common stock	11,444	2,313,948	(a)			1,537,449
Accumulated deficit	(9,190)			(10,879)	(a)	668,284
Total	2,254	2,313,948		(10,879)		2,205,733
TOTAL LIABILITIES AND EQUITY	$ 5,372	$2,318,936		$ (47,696)		$6,608,506

PINNACLE WEST CAPITAL CORPORATION
CONSOLIDATED BALANCE SHEET
ELIMINATING AND ADJUSTING ENTRIES

(a)	Common stock		$2,313,948	
	Accumulated deficit		$ 10,879	
	Other investments			2,324,827

To eliminate PNW investment in subsidiaries

	Common Stock	Earnings/ Dividends	Total
APS	$1,898,067	$ 85,106	$1,983,173
Energy Services	11,444	(9,190)	$ 2,254
SunCor	376,391	(65,375)	311,016
El Dorado	28,046	338	28,384
Total	$2,313,948	$ 10,879	$2,324,827

(b)	Other current liabilities		$ 496	
	Customer and other receivables - net			$ 496

To eliminate intercompany receivables/payables

	A/R PNW	A/P Subs Books
APS	$ 189	$ 189
Energy Services	212	212
SunCor	29	29
El Dorado	66	66
Total	$ 496	$ 496

(c)	Other current liabilities		$ 731	
	Other current assets			$ 731

To eliminate PNW payable to APS

(e)	Minority interest		$ 4,904	
	Real estate investments - net			$ 4,904

To eliminate minority interest of SunCor JV partners

(f)	Real estate investments - net		$ 5,450	
	Other - assets			$ 5,450

To reclass PNW capitalized interest related to SunCor

(g)	Other current liabilities	$ 4,020	
	Other deferred credits		$ 4,020
	To reclass PNW deferred comp to long-term		
(h)	Other deferred debits	$ 5	
	Other - assets		$ 5
	To relcass PNW unamortized debt to long-term		
(i)	Accounts payable	$ 32	
	Accrued taxes		$ 32
	To relcass PNW property tax		
(j)	Deferred investment tax credit	$ 1,009	
	Other deferred debits		$ 1,009
	To relcass PNW ITC from Deferred taxes to Deferred ITC		
(k)	Accrued taxes	$ (11,825)	
	Other deferred debits		$ (11,825)
	To relcass PNW accrued taxes		
(o)	Deferred income taxes-current portion	$ 8,000	
	Deferred income taxes-noncurrent portion	25,257	
	Deferred income taxes		$ 33,257
(p)	Energy Services due to APS	$ 922	
	APS due from Energy Services		$ 922
(q)	Other current liabilities	$ 486	
	Other receivables		$ 486

PINNACLE WEST CAPITAL CORPORATION
CONSOLIDATING INCOME STATEMENT (UNAUDITED)
FOR THE PERIOD ENDED DECEMBER 31, 1999
(THOUSANDS OF DOLLARS)

	PWCC	APS	SUNCOR	ELDO
OPERATING REVENUES:				
Electric		$2,292,798		
Real Estate			130,169	
Total	--	2,292,798	130,169	--
FUEL EXPENSES:				
Fuel for electric generation		243,849		
Purchased power		551,645		
Total	--	795,494	--	--
OPERATING EXPENSES:				
Utility operations and maintenance		437,729		
Real estate operations			118,805	
Depreciation and amortization	266	382,057	3,092	--
Taxes other than income taxes		96,579		
Total	266	916,365	121,897	--
OPERATING INCOME	(266)	580,939	8,272	--
OTHER INCOME (DEDUCTIONS):				
Interest on long-term debt	(5,661)	(132,676)	(8,058)	--
Other interest	(517)	(15,595)	--	--
Capitalized interest	240	6,679	4,745	
Preferred stock dividend requirements		(1,016)		
Other, net	132,814	(11,537)	5,185	19,257
Total	126,876	(154,145)	1,872	19,257
Income from continuing operations b4 income taxes	126,610	426,794	10,144	19,257
Income Tax Expense (Benefit)	(3,277)	159,488	4,080	7,774
Income from continuing operations	129,887	267,306	6,064	11,483
Extraordinary charge	--	(139,885)		
discontinued operations	38,000			
NET INCOME (LOSS)	167,887	127,421	6,064	11,483

	ENERGY SERVICES	ADJUSTMENTS & ELIMINATIONS DEBIT	CREDIT	TOTAL
OPERATING REVENUES:				
Electric	386	$ -- (f)		2,293,184
Real Estate				130,169
Total	386	--	--	2,423,353
FUEL EXPENSES:				
Fuel for electric generation				243,849
Purchased power	615		-- (f)	552,260
Total	615	--	--	796,109
OPERATING EXPENSES:				
Utility operations and maintenance	9,048			446,777
Real estate operations		711 (b)	-- (d)	119,516
Depreciation and amortization	153			385,568
Taxes other than income taxes		27 (c,d)		96,606
Total	9,201	738	--	1,048,467
OPERATING INCOME	(9,430)	(738)	--	578,777
OTHER INCOME (DEDUCTIONS):				
Interest on long-term debt				(146,395)
Other interest			126 (e)	(15,986)
Capitalized interest				11,664
Preferred stock dividend requirements				(1,016)
Other, net	239	135,903 (a,e)	738 (b,c)	10,793
Total	239	135,903	864	(140,940)
Income from continuing operations b4 income taxes	(9,191)	136,641	864	437,837
Income Tax Expense (Benefit)				168,065
Income from continuing operations	(9,191)	136,641	864	269,772
Extraordinary charge				(139,885)
discontinued operations				38,000
NET INCOME (LOSS)	(9,191)	136,641	864	167,887

PINNACLE WEST CAPITAL CORPORATION
CONSOLIDATING INCOME STATEMENT
ELIMINATING ENTRIES

(a)	Other - net (Subs income)	$135,777		
	Retained Earnings			$135,777

To eliminate PWCC Equity in earnings from subsidiairies

	PWCC
APS	$127,421
APS Extraordinary Chg	0
Energy Services	(9,191)
SunCor	6,064
El Dorado	11,483
Total	$135,777

(b)	Real Estate Operations	$ 711		
	Interest Expense (PWCC)			$ 711

To reclass Capitalized Interest for SunCor Land Sales.

(c)	Taxes other than income taxes	$ 27		
	Other - net			$ 27

To reclass PNW property taxes

(e)	Other, net (El Dorado interest income)	$ 126		
	Other interest			$ 126

To eliminate interest on ELD loan to PNW

SUNCOR DEVELOPMENT COMPANY
CONSOLIDATED BALANCE SHEET (UNAUDITED)
FOR THE MONTH ENDED DECEMBER 31, 1999

ACCOUNT DESCRIPTION	1000 SUNCOR	SCOTT D. LPSCO	ANDY D. RANCHLAND	TERRY O. SASI	3500 SMLP	LINDA H. PVGC
CURRENT ASSETS						
CASH AND SHORT TERM INVESTMENTS	6,814,271	1,551,346	287,653	317,208	1,495,236	(16,650)
ACCOUNTS RECEIVABLE	409,109	1,591,526	2,922	94,972	303,750	38,691
INTERCOMPANY ACCOUNTS:						
SASI						
LPSCO	36,630					
SMLP	20,006					
PVGC						3,566,740
WWOS	(147,949)					
GOLDEN HERITAGE - GENERAL 129	1,164,402					
SCM-GENERAL 129	5,386,541					
HOMEBUILDING I/C INTEREST 12904	4,259,103					
HOMEBUILDING CASH ADVANCES	13,617,899					
COMMERCIAL - GENERAL						
SUNRIDGE - DEVELOPMENT	10,985					
SUNRIDGE - GOLF	183,387					
SEDONA - DEVELOPMENT	123,201					
SEDONA - GOLF	131,247					
WIGWAM RESORT	304,244					
HFS FINANCIAL SERVICES	4,712					
SANCTUARY GOLF	116,967					
INTEREST RECEIVABLE	358,026					
NOTES RECEIVABLE	3,242,262					
INVENTORIES						77,335
PREPAID EXPENSES	16,718					86,017
HOME INVENTORY	6,888					
DEFERRED INCOME TAXES	8,000,000					
TOTAL CURRENT ASSETS	44,058,649	3,142,872	290,575	412,180	1,798,986	3,752,133
LONG-TERM ASSETS						
DEVELOPMENT PROJECTS						
CORAL CANYON						
HIDDEN HILLS						
RANCHO VIEJO						
PALM VALLEY						
LITCHFIELD GREENS						
VILLAGE OF LITCHFIELD GREENS						
SCOTTSDALE MOUNTAIN					2,990,878	
MARKETPLACE - AUTOPLEX						
TATUM RANCH	2,296,981					
TALAVI						
WIGWAM OUTLET STORES						
GOLDEN HERITAGE LAND						
BILTMORE ESTATES						
BLACK CANYON COMMERCE PARK						
OTHER COMMERCIAL LAND						
EQUITY INVESTMENTS:						
EQUITY IN CTRPT ASSOC-LLP						
INVEST IN KYRENE ASSOCIATES LLC						
INVEST IN PV APARTMENTS (I & II)						
INVESTMENT IN SUNRIDGE CANYON LLC	4,733,057					
INVESTMENT IN SEDONA GOLF LC	4,532,343					
INVESTMENT IN PLUMCOR REALTY LLC						
INVEST IN TALAVI ASSOCIATES LLC						
INVESTMENT IN WESTWORLD GOLF	2,462,925					
INVESTMENT IN HFS MORTGAGE						
CONSOLIDATED ELIMINATING ENTITIES:						
INVEST IN KABUTO/SUNCOR JV	5,989,478					
INVESTMENT IN WIGWAM OUTLET LLC						
INVEST IN SCOTTS MTN LTD PART	3,661,279					
INVEST IN GOLDEN HERITAGE	2,360,474					
GOLDEN HERITAGE DUE DILIGENCE						
INVESTMENT IN SCM	517,850					
INVESTMENT IN LPSCO	12,370,410					
INVESTMENT IN SASI						
INVESTMENT IN PALM VALLEY	167,320,786					
INVESTMENT IN PALM VALLEY GOLF	5,696,556					
PALM VALLEY GOLF CONTRIB. CAP	(3,566,740)					
INVESTMENT IN RANCHO VIEJO	14,150,291					
INVESTMENT IN RANCHLAND UTILITY	(92,139)					
INVESTMENT IN HIDDEN HILLS	8,831,359					
INVESTMENT IN CORAL CANYON	9,935,792					

ACCOUNT DESCRIPTION	LARRY W. HOMES	5500 PV	WWOS	5501 KABUTO JV	COMM.	3300 H HILLS
CURRENT ASSETS						
CASH AND SHORT TERM INVESTMENTS	318,818	(528,388)	89,489	(26,250)	(537,677)	(504,712)
ACCOUNTS RECEIVABLE	173,037		109,951		253,504	
INTERCOMPANY ACCOUNTS:						
SASI						
LPSCO						
SMLP						
PVGC						
WWOS					372,210	
GOLDEN HERITAGE - GENERAL 129	270,788					
SCM-GENERAL 129	(5,386,541)					
HOMEBUILDING I/C INTEREST 12904	(4,259,103)					
HOMEBUILDING CASH ADVANCES						
COMMERCIAL - GENERAL						
SUNRIDGE - DEVELOPMENT						
SUNRIDGE - GOLF						
SEDONA - DEVELOPMENT						
SEDONA - GOLF						

WIGWAM RESORT						
HFS FINANCIAL SERVICES						
SANCTUARY GOLF						
INTEREST RECEIVABLE						
NOTES RECEIVABLE					141,519	
INVENTORIES					53,128	
PREPAID EXPENSES	31,826	85				
HOME INVENTORY	28,380,385					
DEFERRED INCOME TAXES						
TOTAL CURRENT ASSETS	19,529,209	(528,304)	199,441	(26,250)	282,684	(504,712)
LONG-TERM ASSETS						
DEVELOPMENT PROJECTS						
CORAL CANYON						
HIDDEN HILLS						10,617,585
RANCHO VIEJO						
PALM VALLEY		168,160,448			15,488,115	
LITCHFIELD GREENS		216,402				
VILLAGE OF LITCHFIELD GREENS				12,865,293		
SCOTTSDALE MOUNTAIN						
MARKETPLACE - AUTOPLEX					7,056,083	
TATUM RANCH						
TALAVI					2,317,465	
WIGWAM OUTLET STORES			15,215,844			
GOLDEN HERITAGE LAND	1,417,382					
BILTMORE ESTATES						
BLACK CANYON COMMERCE PARK					2,370,320	
OTHER COMMERCIAL LAND					2,851,358	
EQUITY INVESTMENTS:						
EQUITY IN CTRPT ASSOC-LLP					22,699,776	
INVEST IN KYRENE ASSOCIATES LLC					(89,199)	
INVEST IN PV APARTMENTS (I & II)		623,373				
INVESTMENT IN SUNRIDGE CANYON LLC						
INVESTMENT IN SEDONA GOLF LC						
INVESTMENT IN PLUMCOR REALTY LLC						
INVEST IN TALAVI ASSOCIATES LLC					2,428,130	
INVESTMENT IN WESTWORLD GOLF						
INVESTMENT IN HFS MORTGAGE						
CONSOLIDATED ELIMINATING ENTITIES:						
INVEST IN KABUTO/SUNCOR JV						
INVESTMENT IN WIGWAM OUTLET LLC					3,127,396	
INVEST IN SCOTTS MTN LTD PART						
INVEST IN GOLDEN HERITAGE						
GOLDEN HERITAGE DUE DILIGENCE						
INVESTMENT IN SCM						
INVESTMENT IN LPSCO						
INVESTMENT IN SASI		311,290				
INVESTMENT IN PALM VALLEY						
INVESTMENT IN PALM VALLEY GOLF						
PALM VALLEY GOLF CONTRIB. CAP						
INVESTMENT IN RANCHO VIEJO						
INVESTMENT IN RANCHLAND UTILITY						
INVESTMENT IN HIDDEN HILLS						
INVESTMENT IN CORAL CANYON						

			CONSOLIDATING & ELIMINATING ENTRIES			
ACCOUNT DESCRIPTION	ANDY D. R. VIEJO	3900 C. CANYON	REF	DEBIT	REF	CREDIT
CURRENT ASSETS						
CASH AND SHORT TERM INVESTMENTS	(73,037)	(1,287,140)				
ACCOUNTS RECEIVABLE	258,811				J,Q,X	484,456
INTERCOMPANY ACCOUNTS:						
SASI						
LPSCO					H	36,630
SMLP					J	20,006
PVGC					N	3,566,740
WWOS			Q,O	147,949	Q,O	372,210
GOLDEN HERITAGE - GENERAL 129					A	1,435,189
SCM-GENERAL 129			A	5,386,541	A	5,386,541
HOMEBUILDING I/C INTEREST 12904			C	4,259,103	C	4,259,103
HOMEBUILDING CASH ADVANCES					B	13,617,899
COMMERCIAL - GENERAL						
SUNRIDGE - DEVELOPMENT						
SUNRIDGE - GOLF						
SEDONA - DEVELOPMENT						
SEDONA - GOLF						
WIGWAM RESORT						
HFS FINANCIAL SERVICES						
SANCTUARY GOLF						
INTEREST RECEIVABLE					P	91,841
NOTES RECEIVABLE						
INVENTORIES						
PREPAID EXPENSES		47,961				
HOME INVENTORY	2,825,908	339,614			E	1,750,166
DEFERRED INCOME TAXES						
TOTAL CURRENT ASSETS	3,011,682	(899,565)		9,793,593		31,020,780
LONG-TERM ASSETS						
DEVELOPMENT PROJECTS						
CORAL CANYON		11,316,475				
HIDDEN HILLS					T	6,687,713
RANCHO VIEJO	10,626,364					
PALM VALLEY						
LITCHFIELD GREENS						
VILLAGE OF LITCHFIELD GREENS						
SCOTTSDALE MOUNTAIN						
MARKETPLACE - AUTOPLEX						
TATUM RANCH						
TALAVI						
WIGWAM OUTLET STORES						
GOLDEN HERITAGE LAND						
BILTMORE ESTATES						
BLACK CANYON COMMERCE PARK						
OTHER COMMERCIAL LAND						
EQUITY INVESTMENTS:						
EQUITY IN CTRPT ASSOC-LLP						
INVEST IN KYRENE ASSOCIATES LLC						
INVEST IN PV APARTMENTS (I & II)						
INVESTMENT IN SUNRIDGE CANYON LLC						

INVESTMENT IN SEDONA GOLF LC				R	8,987,210
INVESTMENT IN PLUMCOR REALTY LLC		O	20,243,786	O	24,295,125
INVEST IN TALAVI ASSOCIATES LLC		I	19,595,019	I	23,271,427
INVESTMENT IN WESTWORLD GOLF			-	D	2,360,474
INVESTMENT IN HFS MORTGAGE					
CONSOLIDATED ELIMINATING ENTITIES:				D	517,850
INVEST IN KABUTO/SUNCOR JV				F	12,233,823
INVESTMENT IN WIGWAM OUTLET LLC		L	650,000	L	961,290
INVEST IN SCOTTS MTN LTD PART			-	V	167,320,786
INVEST IN GOLDEN HERITAGE		M	461,618	M	6,158,173
GOLDEN HERITAGE DUE DILIGENCE		N	3,566,740		
INVESTMENT IN SCM		U	0	U	14,150,291
INVESTMENT IN LPSCO		X	92,236	X	1,062,944
INVESTMENT IN SASI		T	0	T	8,831,359
INVESTMENT IN PALM VALLEY		W	42,620	W	9,978,412
INVESTMENT IN PALM VALLEY GOLF					
PALM VALLEY GOLF CONTRIB. CAP					
INVESTMENT IN RANCHO VIEJO					
INVESTMENT IN RANCHLAND UTILITY	1,063,044				
INVESTMENT IN HIDDEN HILLS					
INVESTMENT IN CORAL CANYON					

ACCOUNT DESCRIPTION	CONSOLIDATED
CURRENT ASSETS	
CASH AND SHORT TERM INVESTMENTS	7,900,166.81
ACCOUNTS RECEIVABLE	2,751,817.08
INTERCOMPANY ACCOUNTS:	
SASI	0.00
LPSCO	0.00
SMLP	0.00
PVGC	0.00
WWOS	0.00
GOLDEN HERITAGE - GENERAL 129	0.00
SCM-GENERAL 129	0.00
HOMEBUILDING I/C INTEREST 12904	0.00
HOMEBUILDING CASH ADVANCES	0.00
COMMERCIAL - GENERAL	0.00
SUNRIDGE - DEVELOPMENT	10,985.35
SUNRIDGE - GOLF	183,387.29
SEDONA - DEVELOPMENT	123,200.67
SEDONA - GOLF	131,247.08
WIGWAM RESORT	304,243.52
HFS FINANCIAL SERVICES	4,712.37
SANCTUARY GOLF	116,966.90
INTEREST RECEIVABLE	266,185.50
NOTES RECEIVABLE	3,383,781.12
INVENTORIES	130,463.35
PREPAID EXPENSES	182,606.47
HOME INVENTORY	29,802,628.36
DEFERRED INCOME TAXES	8,000,000.00
TOTAL CURRENT ASSETS	53,292,391.87
LONG-TERM ASSETS	
DEVELOPMENT PROJECTS	
CORAL CANYON	11,316,475.00
HIDDEN HILLS	3,929,872.00
RANCHO VIEJO	10,626,364.30
PALM VALLEY	183,648,562.82
LITCHFIELD GREENS	216,401.50
VILLAGE OF LITCHFIELD GREENS	12,865,293.32
SCOTTSDALE MOUNTAIN	2,990,878.00
MARKETPLACE - AUTOPLEX	7,056,082.50
TATUM RANCH	2,296,981.30
TALAVI	2,317,464.93
WIGWAM OUTLET STORES	15,215,844.02
GOLDEN HERITAGE LAND	1,417,382.32
BILTMORE ESTATES	0.00
BLACK CANYON COMMERCE PARK	2,370,319.68
OTHER COMMERCIAL LAND	2,851,358.19
EQUITY INVESTMENTS:	
EQUITY IN CTRPT ASSOC-LLP	22,699,776.23
INVEST IN KYRENE ASSOCIATES LLC	(89,199.41)
INVEST IN PV APARTMENTS (I & II)	623,372.96
INVESTMENT IN SUNRIDGE CANYON LLC	4,733,057.28
INVESTMENT IN SEDONA GOLF LC	4,532,343.08
INVESTMENT IN PLUMCOR REALTY LLC	0.00
INVEST IN TALAVI ASSOCIATES LLC	2,428,130.22
INVESTMENT IN WESTWORLD GOLF	2,462,925.00
INVESTMENT IN HFS MORTGAGE	0.00
CONSOLIDATED ELIMINATING ENTITIES:	0.00
INVEST IN KABUTO/SUNCOR JV	(2,997,731.29)
INVESTMENT IN WIGWAM OUTLET LLC	(923,943.20)
INVEST IN SCOTTS MTN LTD PART	(15,128.48)
INVEST IN GOLDEN HERITAGE	0.00
GOLDEN HERITAGE DUE DILIGENCE	0.00
INVESTMENT IN SCM	0.00
INVESTMENT IN LPSCO	136,586.22
INVESTMENT IN SASI	0.00
INVESTMENT IN PALM VALLEY	0.00
INVESTMENT IN PALM VALLEY GOLF	0.00
PALM VALLEY GOLF CONTRIB. CAP	0.00
INVESTMENT IN RANCHO VIEJO	0.00
INVESTMENT IN RANCHLAND UTILITY	196.46
INVESTMENT IN HIDDEN HILLS	0.00
INVESTMENT IN CORAL CANYON	0.00

ACCOUNT DESCRIPTION	SUNCOR	SCOTT D. LPSCO	ANDY D. RANCHLAND	TERRY O. SASI	SMLP	LINDA H. PVGC
PROJECT 2000:						
INVESTMENT IN FIDDLESTICKS-SCOTTS	(1,557,881)					
INVESTMENT IN FIDDLESTICKS-TEMPE	596,193					
INVESTMENT IN FUNTASTICKS	1,213,707					
INVESTMENT IN GENERAL COMM OPS	78,582,545					
INVESTMENT IN PV MARKETPLACE	2,307,137					
INVESTMENT IN DYSART/MCDOWELL	872,316					
INVESTMENT IN PV PAVILIONS	2,694,953					

INVESTMENT IN PV CROSSING	150,310					
INVESTMENT IN PALM VALLEY OFFICE PARK	(8,156)					
INVESTMENT IN AUTOPLEX	(203,224)					
INVESTMENT IN TALAVI	(182,886)					
INVESTMENT IN METROCENTER	281,411					
INVESTMENT IN RESTORATION PLACE	(82,105)					
INVESTMENT IN LITCHFIELD PARK OP	121,246					
INVESTMENT IN LP PROF. PLAZA	(643)					
INVESTMENT IN WWOS LLC	(397,454)					
INVESTMENT IN APS PROPERTIES	113,667					
INVESTMENT IN BLACK CANYON CP	(8,126)					
COMMERCIAL PROPERTIES						5,163,154
LONG-TERM NOTES RECEIVABLE	5,687,701					
SDC PHASE I LAND NOTE TO WWOS	1,059,207					
SDC PAYOFF OF WWOS RLC	10,000,000					
SDC LOAN TO LPSCO	300,000					
PROPERTY & EQUIPMENT, NET	773,367			36,696		143,980
DEFERRED ASSETS	3,329,080	366,079	44,008		93,923	175,051
DEFERRED INCOME TAXES	25,120,119					
WATER & SEWER UTILITY PROP, NET		13,921,090	1,134,035			
LPSCO RESTRICTED CASH FUNDS		3,800,491				
DEPOSITS						
TOTAL LONG-TERM ASSETS	371,963,183	18,087,660	1,178,043	36,696	3,084,801	5,482,185
TOTAL ASSETS	416,021,832	21,230,532	1,468,618	448,876	4,883,787	9,234,318
LIABILITIES:						
CURRENT LIABILITIES						
A/P & RETENTION	119,490	237,174	0	29,787	68,109	56,165
ACCRUED LIABILITIES	2,561,017	400,672	101	147	49,404	77,263
INTERCOMPANY ACCOUNTS:						
LPSCO - SDC		36,630				
SMLP - SDC					20,006	
SCM-SDC CASH ADVANCES 267						
GH-SDC INTERCO CAPITAL 265						
WWOS-COM						
WWOS-SDC						
RANCHLAND-RANCHO VIEJO			176,174			
INTEREST PAYABLE	676,610					
S/T NOTES PAYABLE						
$45 MILLION TERM LOAN	3,208,144					
$55 MILLION RLC						
GOLDEN HERITAGE (PEW)						
TEXTRON LOAN - PVGC						
DEF PROFIT & UNEARNED REVENUE	2,318,943			37,193	0	
PWCC INTERCO PAYABLE	635,090					
APS LAND INTERCO PAYABLE						
CUSTOMER DEPOSITS						
TOTAL CURRENT LIABILITIES	9,519,295	674,476	176,275	67,127	137,519	133,428
LONG-TERM LIABILITIES						
LONG-TERM NOTES PAYABLE						
WWOS OWES SDC PH I LAND NOTE						
WWOS RLC PAYOFF BY SDC						
CORPORATE TERM NOTE	38,791,856					
CORPORATE RLC	52,000,000					
LPSCO BONDS		5,335,000				
TEXTRON LOAN - PVGC						3,404,335
OTHER ACCRUED LIABILITIES	4,694,788	1,177,095	0	70,459		
DEFERRED TAXES		17,613	113,584			
LONG-TERM CUSTOMER DEPOSITS		1,492,524	208,050			
CONTRIB PROPERTY AIA						
TOTAL L/T LIABILITIES	95,486,644	8,022,232	321,634	70,459	0	3,404,335
TOTAL LIABILITIES	105,005,939	8,696,708	497,909	137,586	137,519	3,537,763

ACCOUNT DESCRIPTION	LARRY W. HOMES	PV	WWOS	KABUTO JV	COMM.	H HILLS
INVESTMENT IN FIDDLESTICKS-SCOTTS						
INVESTMENT IN FIDDLESTICKS-TEMPE						
INVESTMENT IN FUNTASTICKS						
INVESTMENT IN GENERAL COMM OPS						
INVESTMENT IN PV MARKETPLACE						
INVESTMENT IN DYSART/MCDOWELL						
INVESTMENT IN PV PAVILIONS						
INVESTMENT IN PV CROSSING						
INVESTMENT IN PALM VALLEY OFFICE PARK						
INVESTMENT IN AUTOPLEX						
INVESTMENT IN TALAVI						
INVESTMENT IN METROCENTER						
INVESTMENT IN RESTORATION PLACE						
INVESTMENT IN LITCHFIELD PARK OP						
INVESTMENT IN LP PROF. PLAZA						
INVESTMENT IN WWOS LLC						
INVESTMENT IN APS PROPERTIES						
INVESTMENT IN BLACK CANYON CP						
COMMERCIAL PROPERTIES					27,158,053	
LONG-TERM NOTES RECEIVABLE		498,808				
SDC PHASE I LAND NOTE TO WWOS						
SDC PAYOFF OF WWOS RLC						
SDC LOAN TO LPSCO						
PROPERTY & EQUIPMENT, NET	1,206,867	164,299	77,893			
DEFERRED ASSETS		162,500	75,852		850,452	5,603,404
DEFERRED INCOME TAXES						
WATER & SEWER UTILITY PROP, NET						
LPSCO RESTRICTED CASH FUNDS						
DEPOSITS	123,830					
TOTAL LONG-TERM ASSETS	2,748,079	170,137,119	15,369,589	12,865,293	86,257,949	16,220,989
TOTAL ASSETS	22,277,288	169,608,815	15,569,029	12,839,044	86,540,632	15,716,277
LIABILITIES:						
CURRENT LIABILITIES						
A/P & RETENTION	2,660,070	1,047,497	568,172		516,891	117,872
ACCRUED LIABILITIES	272,800	172,490		17,299	1,001,464	79,333

INTERCOMPANY ACCOUNTS:						
LPSCO - SDC						
SMLP - SDC						
SCM-SDC CASH ADVANCES 267	13,617,456					
GH-SDC INTERCO CAPITAL 265	1,432,265					
WWOS-COM			372,210			
WWOS-SDC			(147,949)			
RANCHLAND-RANCHO VIEJO						
INTEREST PAYABLE			91,841			
S/T NOTES PAYABLE						
$45 MILLION TERM LOAN						
$55 MILLION RLC						
GOLDEN HERITAGE (PEW)						
TEXTRON LOAN - PVGC						
DEF PROFIT & UNEARNED REVENUE		50,000				
PWCC INTERCO PAYABLE						
APS LAND INTERCO PAYABLE						
CUSTOMER DEPOSITS	1,416,373					
TOTAL CURRENT LIABILITIES	19,398,964	1,269,987	884,273	17,299	1,518,354	197,205
LONG-TERM LIABILITIES						
LONG-TERM NOTES PAYABLE						
WWOS OWES SDC PH I LAND NOTE			1,059,207			
WWOS RLC PAYOFF BY SDC			10,000,000			
CORPORATE TERM NOTE						
CORPORATE RLC						
LPSCO BONDS						
TEXTRON LOAN - PVGC						
OTHER ACCRUED LIABILITIES		1,018,042	29,833		78,792	
DEFERRED TAXES						
LONG-TERM CUSTOMER DEPOSITS						
CONTRIB PROPERTY AIA						
TOTAL L/T LIABILITIES	0	1,018,042	11,089,039	0	78,792	0
TOTAL LIABILITIES	19,398,964	2,288,029	11,973,313	17,299	1,597,147	197,205

ACCOUNT DESCRIPTION	ANDY D. R. VIEJO	C. CANYON	REF	DEBIT	REF	CREDIT
INVESTMENT IN FIDDLESTICKS-SCOTTS			S	3,380,396	S	1,822,515
INVESTMENT IN FIDDLESTICKS-TEMPE			S	316,640	S	912,833
INVESTMENT IN FUNTASTICKS					S	1,213,707
INVESTMENT IN GENERAL COMM OPS				0	S	78,582,545
INVESTMENT IN PV MARKETPLACE					S	2,307,137
INVESTMENT IN DYSART/MCDOWELL					S	872,316
INVESTMENT IN PV PAVILIONS					S	2,694,953
INVESTMENT IN PV CROSSING				0	S	150,310
INVESTMENT IN PALM VALLEY OFFICE PARK			S	8,156		
INVESTMENT IN AUTOPLEX			S	203,224		
INVESTMENT IN TALAVI			S	182,886		
INVESTMENT IN METROCENTER					S	281,411
INVESTMENT IN RESTORATION PLACE			S	82,105		
INVESTMENT IN LITCHFIELD PARK OP					S	121,246
INVESTMENT IN LP PROF. PLAZA			S	643		0
INVESTMENT IN WWOS LLC			S	397,454		0
INVESTMENT IN APS PROPERTIES				0	S	113,667
INVESTMENT IN BLACK CANYON CP			S	8,126		0
COMMERCIAL PROPERTIES						
LONG-TERM NOTES RECEIVABLE						
SDC PHASE I LAND NOTE TO WWOS					P	1,059,207
SDC PAYOFF OF WWOS RLC					P	10,000,000
SDC LOAN TO LPSCO					G	300,000
PROPERTY & EQUIPMENT, NET	387,982	41,756				
DEFERRED ASSETS						
DEFERRED INCOME TAXES						
WATER & SEWER UTILITY PROP, NET						
LPSCO RESTRICTED CASH FUNDS						
DEPOSITS		1,989				
TOTAL LONG-TERM ASSETS	12,077,391	11,360,220		49,231,649		387,248,724
TOTAL ASSETS	15,089,073	10,460,655		59,025,242		418,269,504
LIABILITIES:						
CURRENT LIABILITIES						
A/P & RETENTION	189,928	496,863	J,K,Q	312,809		
ACCRUED LIABILITIES	744,870	28,000				
INTERCOMPANY ACCOUNTS:						
LPSCO - SDC			H	36,630		
SMLP - SDC			J	20,006		
SCM-SDC CASH ADVANCES 267			B	13,617,456		
GH-SDC INTERCO CAPITAL 265			A	1,432,265		
WWOS-COM			O	372,210		
WWOS-SDC			Q	0	Q	147,949
RANCHLAND-RANCHO VIEJO			X	176,174		0
INTEREST PAYABLE			P	91,841		
S/T NOTES PAYABLE						
$45 MILLION TERM LOAN						
$55 MILLION RLC						
GOLDEN HERITAGE (PEW)						
TEXTRON LOAN - PVGC					*	59,956
DEF PROFIT & UNEARNED REVENUE			E	1,750,166		
PWCC INTERCO PAYABLE						
APS LAND INTERCO PAYABLE						
CUSTOMER DEPOSITS						
TOTAL CURRENT LIABILITIES	934,798	524,863	0	17,809,557	0	207,905
LONG-TERM LIABILITIES						
LONG-TERM NOTES PAYABLE						
WWOS OWES SDC PH I LAND NOTE			P	1,059,207		
WWOS RLC PAYOFF BY SDC			P	10,000,000		
CORPORATE TERM NOTE						
CORPORATE RLC						
LPSCO BONDS						
TEXTRON LOAN - PVGC			*	59,956		
OTHER ACCRUED LIABILITIES						
DEFERRED TAXES						

LONG-TERM CUSTOMER DEPOSITS					
CONTRIB PROPERTY AIA					
TOTAL L/T LIABILITIES	0	0		11,119,163	0
TOTAL LIABILITIES	934,798	524,863		28,928,720	207,905

ACCOUNT DESCRIPTION	CONSOLIDATED
INVESTMENT IN FIDDLESTICKS-SCOTTS	0.00
INVESTMENT IN FIDDLESTICKS-TEMPE	0.00
INVESTMENT IN FUNTASTICKS	0.00
INVESTMENT IN GENERAL COMM OPS	0.00
INVESTMENT IN PV MARKETPLACE	0.00
INVESTMENT IN DYSART/MCDOWELL	0.00
INVESTMENT IN PV PAVILIONS	0.00
INVESTMENT IN PV CROSSING	0.00
INVESTMENT IN PALM VALLEY OFFICE PARK	0.00
INVESTMENT IN AUTOPLEX	0.00
INVESTMENT IN TALAVI	0.00
INVESTMENT IN METROCENTER	0.00
INVESTMENT IN RESTORATION PLACE	0.00
INVESTMENT IN LITCHFIELD PARK OP	0.00
INVESTMENT IN LP PROF. PLAZA	0.00
INVESTMENT IN WWOS LLC	0.00
INVESTMENT IN APS PROPERTIES	0.00
INVESTMENT IN BLACK CANYON CP	0.00
COMMERCIAL PROPERTIES	32,321,206.48
LONG-TERM NOTES RECEIVABLE	6,186,508.60
SDC PHASE I LAND NOTE TO WWOS	0.00
SDC PAYOFF OF WWOS RLC	0.00
SDC LOAN TO LPSCO	0.00
PROPERTY & EQUIPMENT, NET	2,832,839.84
DEFERRED ASSETS	10,700,349.77
DEFERRED INCOME TAXES	25,120,118.87
WATER & SEWER UTILITY PROP, NET	15,055,125.04
LPSCO RESTRICTED CASH FUNDS	3,800,490.75
DEPOSITS	125,819.26
TOTAL LONG-TERM ASSETS	388,852,123.56
TOTAL ASSETS	442,144,515.43
LIABILITIES:	
CURRENT LIABILITIES	
A/P & RETENTION	5,795,209.16
ACCRUED LIABILITIES	5,404,859.61
INTERCOMPANY ACCOUNTS:	0.00
LPSCO - SDC	0.00
SMLP - SDC	0.00
SCM-SDC CASH ADVANCES 267	0.00
GH-SDC INTERCO CAPITAL 265	(0.00)
WWOS-COM	0.00
WWOS-SDC	0.00
RANCHLAND-RANCHO VIEJO	0.00
INTEREST PAYABLE	676,610.21
S/T NOTES PAYABLE	
$45 MILLION TERM LOAN	3,208,144.14
$55 MILLION RLC	0.00
GOLDEN HERITAGE (PEW)	0.00
TEXTRON LOAN - PVGC	59,955.93
DEF PROFIT & UNEARNED REVENUE	655,970.05
PWCC INTERCO PAYABLE	635,090.27
APS LAND INTERCO PAYABLE	0.00
CUSTOMER DEPOSITS	1,416,372.50
TOTAL CURRENT LIABILITIES	17,852,211.87
LONG-TERM LIABILITIES	
LONG-TERM NOTES PAYABLE	
WWOS OWES SDC PH I LAND NOTE	0.00
WWOS RLC PAYOFF BY SDC	0.00
CORPORATE TERM NOTE	38,791,855.86
CORPORATE RLC	52,000,000.00
LPSCO BONDS	5,335,000.00
TEXTRON LOAN - PVGC	3,344,379.10
OTHER ACCRUED LIABILITIES	7,069,009.45
DEFERRED TAXES	131,196.96
LONG-TERM CUSTOMER DEPOSITS	1,700,574.20
CONTRIB PROPERTY AIA	0.00
TOTAL L/T LIABILITIES	108,372,015.57
TOTAL LIABILITIES	126,224,227.44

ACCOUNT DESCRIPTION	SUNCOR	SCOTT D. LPSCO	ANDY D. RANCHLAND	TERRY O. SASI	SMLP	LINDA H. PVGC
MINORITY INTEREST						
SDC COMMON STOCK	1,022,000					
SDC ADDITIONAL PAID IN CAPITAL	375,368,522					
SDC EARNED SURPLUS-BEGINNING	(71,438,657)					
SDC EARNED SURPLUS-CURRENT	6,064,028					
SUBSIDIARY EARNINGS-CURRENT		820,619	(92,236)	(62,491)	3,495,918	(534,796)
SUBSIDIARY EQUITY:						
LPSCO		11,713,205				
SASI				373,781		
SMLP #3500					1,250,349	
PVGC						6,231,352
HOMEBUILDING						
PALM VALLEY #5500						
WWOS #4400						
KABUTO JV #3000						
COMMERCIAL PROPERTIES #2000						
HIDDEN HILLS #3300						
RANCHO VIEJO #6600						
RANCHLAND UTILITY			1,062,944			

CORAL CANYON #3900						
TOTAL EQUITY	311,015,893	12,533,823	970,709	311,290	4,746,268	5,696,556
TOTAL LIABS AND EQUITY	416,021,832	21,230,531	1,468,618	448,876	4,883,787	9,234,318

ACCOUNT DESCRIPTION	LARRY W. HOMES	PV	WWOS	KABUTO JV	COMM.	H HILLS
MINORITY INTEREST						
SDC COMMON STOCK						
SDC ADDITIONAL PAID IN CAPITAL						
SDC EARNED SURPLUS-BEGINNING						
SDC EARNED SURPLUS-CURRENT						
SUBSIDIARY EARNINGS-CURRENT	1,198,047	4,926,636	(455,622)		6,553,333	90,290
SUBSIDIARY EQUITY:						
LPSCO						
SASI						
SMLP #3500						
PVGC						
HOMEBUILDING	1,680,277					
PALM VALLEY #5500		162,394,150				
WWOS #4400			4,051,339			
KABUTO JV #3000				12,821,745		
COMMERCIAL PROPERTIES #2000					78,390,152	
HIDDEN HILLS #3300						15,428,782
RANCHO VIEJO #6600						
RANCHLAND UTILITY						
CORAL CANYON #3900						
TOTAL EQUITY	2,878,324	167,320,786	3,595,717	12,821,745	84,943,486	15,519,072
TOTAL LIABS AND EQUITY	22,277,288	169,608,815	15,569,029	12,839,044	86,540,632	15,716,277

ACCOUNT DESCRIPTION	ANDY D. R. VIEJO	C. CANYON	REF		DEBIT	REF	CREDIT
MINORITY INTEREST				I	10,066,214	I,R	14,970,609
SDC COMMON STOCK							
SDC ADDITIONAL PAID IN CAPITAL							
SDC EARNED SURPLUS-BEGINNING							
SDC EARNED SURPLUS-CURRENT							
SUBSIDIARY EARNINGS-CURRENT	1,414,717	(42,620)	D,I,M,O,S,U,V,W,T		18,499,560	F,L,T,X	1,187,765
SUBSIDIARY EQUITY:							
LPSCO				F,G	11,713,205		
SASI				L	1,023,781	L	650,000
SMLP #3500				I	30,911,582	I	29,661,233
PVGC				M	6,231,352		0
HOMEBUILDING				D	1,680,277		0
PALM VALLEY #5500				V	162,394,150		
WWOS #4400				O	24,295,125	O	20,243,786
KABUTO JV #3000				R	12,821,745		
COMMERCIAL PROPERTIES #2000				S	78,390,152		0
HIDDEN HILLS #3300				T	15,431,852	T	3,070
RANCHO VIEJO #6600	12,739,558			U	12,825,260	U	85,702
RANCHLAND UTILITY				X	1,062,944	X	0
CORAL CANYON #3900		9,978,412		W	9,978,412	W	0
TOTAL EQUITY	14,154,275	9,935,792			387,259,398		51,831,555
TOTAL LIABS AND EQUITY	15,089,073	10,460,655			426,254,331		67,010,069

ACCOUNT DESCRIPTION	CONSOLIDATED
MINORITY INTEREST	4,904,395.09
SDC COMMON STOCK	1,022,000.00
SDC ADDITIONAL PAID IN CAPITAL	375,368,521.94
SDC EARNED SURPLUS-BEGINNING	(71,438,656.87)
SDC EARNED SURPLUS-CURRENT	6,064,028.14
SUBSIDIARY EARNINGS-CURRENT	(0.00)
SUBSIDIARY EQUITY:	
LPSCO	0.00
SASI	0.00
SMLP #3500	0.00
PVGC	0.00
HOMEBUILDING	0.00
PALM VALLEY #5500	0.00
WWOS #4400	0.00
KABUTO JV #3000	0.00
COMMERCIAL PROPERTIES #2000	0.00
HIDDEN HILLS #3300	0.00
RANCHO VIEJO #6600	0.00
RANCHLAND UTILITY	0.00
CORAL CANYON #3900	0.00
TOTAL EQUITY	311,015,893.21
TOTAL LIABS AND EQUITY	442,144,515.74

SUNCOR DEVELOPMENT COMPANY
CONSOLIDATING BALANCE SHEET
DECEMBER 1999 CONSOLIDATING AND ELIMINATING ENTRIES

	DEBIT	CREDIT
A. SCM INTERCO A/P TO SDC	$5,386,541.01	
SDC A/R FROM SCM		$5,386,541.01
GH INTERCO CAPITAL FROM SDC - ACQUISITION	$1,432,265.22	
GH INTERCO A/P TO SDC		$270,787.72
SDC A/R FROM GH		$1,164,401.51
B. HOMEBUILDING CASH ADVANCES FROM SDC	$13,617,456.15	
SDC CASH ADVANCES TO HOMEBUILDING		$13,617,898.62
C. SCM INTERCO CAPPED INTEREST	$4,259,103.31	$0.00
SDC INTERCO INTEREST A/R FROM SCM		$4,259,103.32
ELIMINATE INTERCO RECEIVABLES/PAYABLES BETWEEN HOMEBUILDING AND SDC		
D. HOMEBUILDING ACCUMULATED EARNINGS	$1,680,277.20	
SDC INVESTMENT IN GH		$2,360,474.40
SDC DUE DILIGENCE COSTS - GHH ACQUISITION		
SDC INVESTMENT IN SCM		$517,849.94
HOMEBUILDING CURRENT YEAR EARNINGS	$1,198,047.14	
ELIMINATE SDC INVESTMENT IN GOLDEN HERITAGE & SCM		
E. DEFERRED INTERCO PROFIT	$1,750,166.26	
HOME INVENTORY		$1,750,166.26
ELIMINATE DEFERRED PROFIT ON INTERCO LOT SALES TO HOMEBUILDING		
F. LPSCO COMMON STOCK	$78,200.00	
LPSCO PAID IN CAPITAL	$10,638,917.85	
LPSCO EARNINGS - PRIOR	$696,086.70	
LPSCO INCOME TAXES		
LPSCO EARNINGS - CURRENT YEAR	$820,618.80	
SDC INVESTMENT IN LPSCO - CONTRIB CAPITAL		$10,717,117.86
SDC INVESTMENT IN LPSCO - EARNINGS		$1,516,705.49
SDC DEFERRED TAXES DIFFERENTIAL		$0.00
ELIMINATE SDC INVESTMENT IN LPSCO		
G. LPSCO LONG-TERM NOTES PAYABLE	$300,000.00	
SDC LONG-TERM NOTES RECEIVABLE		$300,000.00
ELIMINATE LPSCO INTERCOMPANY NOTE WITH SDC		
H. LPSCO ACCOUNTS PAYABLE	$36,630.11	
SDC ACCOUNTS RECEIVABLE		$36,630.11
ELIMINATE LPSCO INTERCOMPANY A/R WITH SDC		
I. SMLP CONTRIBUTED CAPITAL - MINORITY INT		$10,066,214.00
SMLP CONTRIBUTED CAPITAL - SDC GP	$490,147.01	
SMLP DISTRIBUTED CAPITAL - SDC GP		$12,853,612.00
SMLP CONTRIBUTED CAPITAL - SDC LP	$2,100,000.00	
SMLP DISTRIBUTED CAPITAL - SDC LP		$6,741,407.00
SMLP EARNINGS - PRIOR	$28,321,435.40	
SMLP EARNINGS - CURRENT YEAR	$3,495,918.29	
MINORITY INTEREST CONTRIBUTED CAPITAL	$10,066,214.00	
MINORITY INTEREST - PRIOR (35%)		$9,912,502.39
MINORITY INTEREST - CURRENT YEAR (35%)		$1,223,571.40
SDC INVESTMENT IN SMLP - LP		$2,100,000.00
SDC DISTRIBUTIONS FROM SMLP - LP	$6,743,407.00	
SDC INVESTMENT IN SMLP - GP		$490,147.01
SDC DISTRIBUTIONS FROM SMLP - GP	$12,851,612.00	
SDC INVESTMENT IN SMLP - EARNINGS		$20,681,279.90
SDC LAND BASIS DIFFERENTIAL		
ELIMINATE SDC INVESTMENT IN SMLP #3500		
J. SMLP ACCOUNTS PAYABLE	$20,005.97	

	SDC ACCOUNTS RECEIVABLE		$20,005.97
	GH ACCOUNTS PAYABLE	$303,750.00	
	SMLP ACCOUNTS RECEIVABLE		$303,750.00
	ELIMINATE SMLP INTERCOMPANY A/R WITH SDC AND HOMEBUILDING (PREMIUMS)		
L.	SASI CONTRIBUTED CAPITAL	$489,023.22	
	SASI CAPITAL DISTRIBUTIONS		$650,000.00
	SASI EARNINGS - PRIOR	$534,757.95	
	SASI EARNINGS - CURRENT YEAR		$62,491.00
	PV INVESTMENT IN SASI - CONTRIB CAPITAL		$489,023.22
	PV INVESTMENT IN SASI - DISTRIBUTIONS	$650,000.00	
	PV INVESTMENT IN SASI - EARNINGS		$472,266.95
	ELIMINATE PALM VALLEY INVESTMENT IN SASI		
M.	PVGC CONTRIBUTED CAPITAL	$6,158,173.14	
	PVGC EARNINGS - PRIOR	$73,178.79	
	PVGC EARNINGS - CURRENT YEAR		$534,796.30
	SDC INVESTMENT IN PVGC - EARNINGS	$461,617.51	
	SDC INVESTMENT IN PVGC - CONTRIB CAPITAL		$6,158,173.14
	ELIMINATE SDC INVESTMENT IN PALM VALLEY GOLF		
N.	SDC CONTRIB. CAPITAL TO PVGC	$3,566,739.66	
	PVGC ACCOUNTS RECEIVABLE		$3,566,739.66
	ELIMINATE PALM VALLEY GOLF INTERCOMPANY A/R WITH SDC		
O.	WWOS CONTRIBUTED CAPITAL - PHASE 1	$9,500,000.00	
	WWOS CONTRIBUTED CAPITAL - PHASE 2	$13,408,869.75	
	WWOS CONTRIBUTED WORKING CAPITAL	$1,386,255.25	
	WWOS EARNINGS - PRIOR		$2,023,394.41
	WWOS EARNINGS - CURRENT YEAR		$455,622.46
	WWOS CAPITAL DISTRIBUTIONS - PHASE 1		$9,500,000.00
	WWOS CAPITAL DISTRIBUTIONS - PHASE 2		$4,967,126.16
	WWOS PREFERRED RETURN - PHASE 1		$287,567.78
	WWOS PREFERRED RETURN - PHASE 2		$3,465,697.50
	SDC INVESTMENT IN WWOS - PHASE 1		$9,500,000.00
	SDC INVESTMENT IN WWOS - PHASE 2		$13,408,869.75
	SDC INVESTMENT IN WWOS -CONTRIBUTED CAPITAL		$1,386,255.25
	SDC INVESTMENT IN WWOS - EARNINGS	$2,023,394.41	
	SDC DISTRIBUTIONS FROM WWOS - PHASE 1	$9,500,000.00	
	SDC DISTRIBUTIONS FROM WWOS - PHASE 2	$4,967,126.16	
	SDC PREFERRED RETURN - PHASE 1	$287,567.78	
	SDC PREFERRED RETURN - PHASE 2	$3,465,697.50	
	SDC BASIS DIFFERENTIAL PH I BUILDINGS		
	SDC BASIS DIFFERENTIAL LAND		
	SDC 1994 CAPPED INTEREST ON WWOS		
	SDC 1995 DEVELOPMENT FEES		
	WWOS I/C A/P - COMMERCIAL	$372,209.61	
	COMMERCIAL I/C A/R - WWOS		$372,209.61
	ELIMINATE SDC COMMERCIAL INVESTMENT IN WIGWAM OUTLET STORES #4400		
P.	WWOS INTEREST PAYABLE - PHASE 1 LAND	$24,028.03	
	WWOS INTEREST PAYABLE - RLC	$67,812.50	
	SDC INTEREST RECEIVABLE - PHASE 1 LAND		$24,028.03
	SDC INTEREST RECEIVABLE - RLC		$67,812.50
	WWOS NOTES PAYABLE - PHASE 1 LAND	$1,059,206.67	
	SDC NOTES RECEIVABLE - PHASE 1 LAND		$1,059,206.67
	WWOS NOTES PAYABLE - RLC	$10,000,000.00	
	SDC NOTES RECEIVABLE - RLC		$10,000,000.00
	ELIMINATE WWOS INTERCOMPANY NOTES AND INTEREST WITH SDC		
Q.	WWOS ACCOUNTS PAYABLE	$147,948.78	
	SDC ACCOUNTS RECEIVABLE		$147,948.78
	WWOS MANAGEMENT FEE PAYABLE	$4,532.05	
	SDC COMMERCIAL A/R		$4,532.05
	ELIMINATE WWOS INTERCOMPANY A/R WITH SDC		
R.	KABUTO CONTRIBUTED CAPITAL - SDC	$8,987,209.60	
	KABUTO CONTRIBUTED CAPITAL - KABUTO	$3,834,535.30	
	MINORITY INTEREST		$3,834,535.30
	SDC INVESTMENT IN KABUTO - CONTR CAPITAL		$6,098,494.79
	BALANCING PLUG		$2,888,714.81
	SDC BASIS DIFFERENTIAL IN LAND		
	SDC DEVELOPMENT COSTS		
	ELIMINATE SDC INVESTMENT IN KABUTO JV #3000		
S.	COMMERCIAL OPS CONTRIBUTED CAPITAL	$74,293,346.97	
	COMMERCIAL EARNINGS - PRIOR	$4,096,805.16	
	COMMERCIAL EARNINGS - CURRENT YEAR	$6,553,333.43	
	SDC INVEST IN GEN COMMERCIAL OPS - EARNINGS		$3,711,897.29
	SDC INVEST IN GEN COMMERCIAL OPS - CONT CAPITAL		$74,870,647.30

	SDC INVESTMENT IN OUTER LIMITS - PURCHASE		$1,822,514.94
	SDC INVESTMENT IN FIDDLE (SCOTTS) - CONT CAPITAL	$2,856,749.32	
	SDC INVESTMENT IN FIDDLE (SCOTTS) - EARNINGS	$523,646.70	
	SDC INVESTMENT IN FUNTASTICKS - CONT CAPITAL		$779,466.39
	SDC INVESTMENT IN FUNTASTICKS - EARNINGS		$434,240.58
	SDC INVESTMENT IN FIDDLE (TEMPE) - CONT CAPITAL	$316,639.78	
	SDC INVESTMENT IN FIDDLE (TEMPE) - EARNINGS		$912,832.69
	SDC INVESTMENT IN APS PROPERTIES - EARNINGS		$113,667.31
	SDC INVESTMENT IN BLACK CANYON CP - EARNINGS	$8,126.09	
	SDC INVESTMENT IN PV MARKETPLACE - EARNINGS		$2,307,137.27
	SDC INVESTMENT IN PV PAVILIONS - EARNINGS		$2,694,953.30
	SDC INVESTMENT IN DYSART/MCDOWELL CENTER		$872,316.24
	SDC INVESTMENT IN PV CROSSING - EARNINGS		$150,309.61
	SDC INVESTMENT IN PV OFFICE PARK - EARNINGS	$8,156.32	
	SDC INVESTMENT IN METROCENTER - EARNINGS		$281,410.66
	SDC INVESTMENT IN REST PLACE - EARNINGS	$82,105.37	
	SDC INVESTMENT IN LITCHFIELD OTHER - EARNINGS		$121,246.12
	SDC INVESTMENT IN AUTOPLEX - EARNINGS	$203,224.40	
	SDC INVESTMENT IN TALAVI - EARNINGS	$182,886.06	
	SDC INVESTMENT IN WWOS - EARNINGS	$397,454.46	
	SDC INVESTMENT IN LP PROF. PLAZA - EARNINGS	$643.44	
	ELIMINATE SDC INVESTMENT IN COMMERCIAL OPERATIONS #2000		
T.	HIDDEN HILLS CONTRIBUTED CAPITAL	$8,744,139.11	
	GLAZ CONTRIBUTED CAPITAL, NET	$6,687,713.00	
	GLAZ INVESTMENT IN HIDDEN HILLS - CONT CAPITAL		$6,687,713.00
	HIDDEN HILLS EARNINGS - PRIOR		$3,069.71
	HIDDEN HILLS EARNINGS - CURRENT YEAR	$90,289.50	
	SDC INVESTMENT IN HIDDEN HILLS - EARNINGS		$87,219.79
	SDC INVESTMENT IN HIDDEN HILLS - CONT CAPITAL		$8,744,139.11
	ELIMINATE SDC INVESTMENT IN HIDDEN HILLS JV #3300		
U.	SDC INVESTMENT IN RANCHO VIEJO - EARNINGS		$1,329,015.08
	SDC INVESTMENT IN RANCHO VIEJO - CAPITAL		$12,821,275.56
	RANCHO VIEJO CONTRIBUTED CAPITAL	$12,825,259.78	
	RANCHO VIEJO EARNINGS - PRIOR		$85,701.63
	RANCHO VIEJO EARNINGS - CURRENT YEAR	$1,414,716.71	
	ELIMINATE SDC INVESTMENT IN RANCHO VIEJO JV #6600		
V.	PV CONTRIBUTED CAPITAL	$152,768,812.48	
	PV EARNINGS - PRIOR	$9,625,337.53	
	PV EARNINGS - CURRENT YEAR	$4,926,635.98	
	SDC INVESTMENT IN PALM VALLEY - EARNINGS		$14,551,973.51
	SDC INVESTMENT IN PALM VALLEY - DEVELOP		$152,768,812.48
	ELIMINATE SDC INVESTMENT IN PALM VALLEY #5500		
W.	CORAL CANYON CONTRIBUTED CAPITAL	$9,978,412.11	
	CORAL CANYON - CURRENT YEAR		$42,619.70
	SDC INVESTMENT IN CORAL CANYON - DEVELOP		$9,978,412.11
	SDC INVESTMENT IN CORAL CANYON - EARNINGS	$42,619.70	
	ELIMINATE SDC INVESTMENT IN CORAL CANYON #3900		
X.	RANCHLAND - CURRENT YEAR		$92,235.67
	RANCHLAND - CONTRIBUTED CAPITAL	$1,062,944.39	
	RANCHLAND - DUE TO/FROM RANCHO VIEJO	$176,174.00	
	RANCHO INVESTMENT IN RANCHLAND UTILTY-CAPITAL		$1,062,944.39
	RANCHO INVESTMENT IN RANCHLAND UTILTY-EARNINGS	$92,235.67	
	RANCHO - DUE TO/FROM RANCHLAND UTILITIES		$176,174.00
	ELIMINATE RANCHO INVESTMENT IN RANCHLAND UTILITY		

SunCor Development Company
Consolidating Income Statement
For the Year Ending December 31, 1999 (Unaudited)

Account Description	SUNCOR	LPSCO	RANCHLAND UTILITY	SCTS MTN	PVGC	GHH
Revenues						
Home Sales	--	--	--	--	--	64,830,130
Land Sales	30,146,383	--	--	7,104,128	--	--
Commercial Properties	5,801,571	--	--	--	1,978,755	--
Utility Sales	--	2,853,412	7,692	--	--	--
Management Fees	1,540,937	--	--	--	--	--
Total Operating Revenues	37,488,891	2,853,412	7,692	7,104,128	1,978,755	64,830,130
Operating Expenses						
Cost of Homes Sold	(0)	--	--	--	--	54,969,177
Cost of Land Sold	18,807,702	--	--	3,442,629	--	--
Commercial Properties	5,561,964	--	--	--	193,879	--
Utility Expense	--	1,785,921	99,915	--	--	--
Land Project Costs	2,329,986	--	--	98,223	--	--
General & Administrative	10,118,243	--	--	89,814	1,783,238	5,449,460
Depreciation & Amortization	1,111,951	276,637	--	--	198,536	647,984
Total Operating Expenses	37,929,845	2,062,558	99,915	3,630,666	2,175,653	61,066,621
Net Operating Income/(Loss)	(440,954)	790,854	(92,223)	3,473,462	(196,898)	3,763,509
Other Income and Gains						
Equity in Joint Ventures	4,854,693	--	--	--	--	--
Interest Income	695,311	123,893	--	22,457	--	--
Other	--	--	--	--	--	(483,855)
Total Other Income and Gains	5,550,004	123,893	--	22,457	--	(483,855)
Interest Expense, Net						
Interest Expense	6,509,298	202,569	--	--	337,898	--
Less: Capitalized Interest	(4,745,280)	--	--	--	--	--
Total Interest Expense, Net	1,764,018	202,569	--	--	337,898	--
Minority Interest	1,018,365	--	--	--	--	--
Income before Taxes	2,326,667	712,178	(92,223)	3,495,918	(534,796)	3,279,654
Income Taxes	4,188,321	(108,441)	--	--	--	--
NET INCOME/(LOSS)	$ (1,861,653)	$ 820,619	$ (92,223)	$ 3,495,918	$ (534,796)	$ 3,279,654

Account Description	WWOS	HIDDEN HILLS	CORAL CANYON	RANCHO VIEJO	CONSOLIDATED INCOME
Revenues					
Home Sales	--	--	--	12,756,318	77,586,447
Land Sales	675,000	260,000	--	121,000	38,306,511
Commercial Properties	1,996,347	--	--	--	9,776,673
Utility Sales	--	--	--	--	2,861,104
Management Fees	--	--	--	--	1,540,937
Total Operating Revenues	2,671,347	260,000	--	12,877,318	130,071,672
Operating Expenses					
Cost of Homes Sold	--	--	--	9,925,940	64,895,117
Cost of Land Sold	284,427	169,711	--	88,226	22,792,694
Commercial Properties	1,066,148	--	--	--	6,821,991
Utility Expense	--	--	--	--	1,885,835
Land Project Costs	--	--	--	543,823	2,972,032
General & Administrative	--	--	42,620	838,219	18,321,614
Depreciation & Amortization	774,396	--	--	82,902	3,092,406
Total Operating Expenses	2,124,971	169,711	42,620	11,479,130	120,781,689
Net Operating Income/(Loss)	546,377	90,290	(42,620)	1,398,188	9,289,983
Other Income and Gains					
Equity in Joint Ventures	--	--	--	--	4,854,690
Interest Income	6,244	--	--	929	848,734
Other	--	--	--	15,700	(518,406)
Total Other Income and Gains	6,244	--	--	16,629	5,185,018
Interest Expense, Net					
Interest Expense	1,008,243	--	--	--	8,058,008
Less: Capitalized Interest	--	--	--	--	(4,745,280)
Total Interest Expense, Net	1,008,243	--	--	--	3,312,728
Minority Interest	--	--	--	--	1,018,365
Income before Taxes	(455,622)	90,290	(42,620)	1,414,717	10,143,908
Income Taxes	--	--	--	--	4,079,880
NET INCOME/(LOSS)	$ (455,622)	$ 90,290	$ (42,620)	$ 1,414,717	$ 6,064,028

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Company: PINNACLE WEST CAPITAL CORP
Form Type: U-3A-2 SEC File #: 069-00306
Description: FORM U-3A-2
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Adopted November 9, 1939 File No. 69-306

SECURITIES AND EXCHANGE COMMISSION
Washington, D.C.

FORM U-3A-2

STATEMENT BY HOLDING COMPANY
CLAIMING EXEMPTION UNDER RULE U-3A-2
FROM THE PROVISIONS OF THE
PUBLIC UTILITY HOLDING COMPANY ACT OF 1935

To Be Filed Annually Prior to March 1

Pinnacle West Capital Corporation

(Name of Company)

hereby files with the Securities and Exchange Commission, pursuant to Rule 2, its statement claiming exemption as a holding company from the provisions of the Public Utility Holding Company Act of 1935, and submits the following information:

1. NAME, STATE OF ORGANIZATION, LOCATION AND NATURE OF BUSINESS OF CLAIMANT AND EVERY SUBSIDIARY THEREOF, OTHER THAN ANY EXEMPT WHOLESALE GENERATOR (EWG) OR FOREIGN UTILITY COMPANY IN WHICH CLAIMANT DIRECTLY OR INDIRECTLY HOLDS AN INTEREST.

Pinnacle West Capital Corporation ("Claimant"), having been incorporated on February 20, 1985 under the laws of the State of Arizona, and having its principal executive offices at 400 East Van Buren, Suite 700, Phoenix, Arizona 85004, was organized principally to acquire and hold securities of other corporations for investment purposes. Claimant currently holds stock in the following subsidiaries:

a. Arizona Public Service Company ("APS" or the "Company"), is engaged principally in serving electricity in the State of Arizona. Incorporated in 1920 under the laws of the State of Arizona and having its principal executive offices at 400 North Fifth Street, Phoenix, Arizona 85004, APS became a subsidiary of the Claimant pursuant to a corporate restructuring plan approved by the Company's shareholders on April 18, 1985.

(1) AXIOM Power Solutions, Inc. ("AXIOM") -- an Arizona corporation having been incorporated on October 29, 1996 and having its principal executive offices at 400 E. Van Buren, Phoenix, Arizona 85004, was organized primarily to sell security and energy management products and services. AXIOM is a wholly-owned subsidiary of APS.

(2) Bixco, Inc. ("Bixco") -- an Arizona corporation having been incorporated on June 4, 1971 and having its principal executive offices at 400 North Fifth Street, Phoenix, Arizona 85004, was organized primarily to conduct exploration activities for energy resources and other valuable minerals. Subsequent to the sale of its oil and natural gas properties in 1981, Bixco has been inactive. Bixco is a wholly-owned subsidiary of APS.

(3) APS Energy Services Company, Inc. ("APSES") -- an Arizona Corporation having been incorporated on November 6, 1998 and having its principal executive offices at 400 E. Van Buren, Phoenix, Arizona 85004, was organized primarily to sell energy, products and services. APSES is a wholly-owned subsidiary of APS.

b. SunCor Development Company ("SunCor") - an Arizona corporation having been incorporated on June 30, 1965 and having its

principal executive offices at 3838 North Central Avenue, Suite 1500, Phoenix, Arizona 85012, is a wholly-owned subsidiary of Claimant engaged primarily in the owning, holding and development of real property.

(1) SunCor Resort & Golf Management, Inc. ("Resort & Golf Management") (previously named "SunCor Resort Management, Inc." and "SunCor Farms, Inc.") -- an Arizona corporation having been incorporated on December 31, 1986 and having its principal executive offices at 3838 North Central Avenue' Suite 1500, Phoenix, Arizona 85012, operates and manages hotel, golf, food and beverage for the Wigwam Resort and Country Club, Sedona Golf Resort, SunRidge Canyon Golf Club, and Palm Valley Golf Club. Resort & Golf Management is a wholly-owned subsidiary of SunCor.

(2) Litchfield Park Service Company ("LPSCO") -- an Arizona corporation having been incorporated on September 21, 1954 and having its principal executive offices at 501 East Plaza Circle, Suite B, Litchfield Park, Arizona 85340, is a regulated public utility engaged in providing water and sewer services to commercial and residential customers. LPSCO became a wholly-owned subsidiary of SunCor on December 31,1986.

(3) Golden Heritage Homes, Inc.. ("Golden Heritage Homes") -- (previously named "SunCor Homes, Inc.", "LGR, Inc." and "WGP Realty, Inc.") an Arizona corporation having been incorporated on May 14, 1986 and having its principal executive offices at 3838 North Central Avenue, Suite 1500, Phoenix, Arizona 85012, was organized to provide brokerage and realty services in the sale of commercial and residential real property. Golden Heritage Homes is a wholly-owned subsidiary of SunCor.

(i) Golden Heritage Construction, Inc. ("GH Construction") -- an Arizona corporation having been incorporated on December 30, 1993 and having its principal executive offices at 3838 North Central Avenue, Suite 1500, Phoenix, Arizona 85012, was organized to serve as a general residential contractor. GH Construction became a wholly-owned

subsidiary of Golden Heritage Homes, Inc. on January 1, 1996.

(4) SCM, Inc. ("SCM") -- an Arizona corporation having been incorporated on May 14, 1991 and having its principal executive offices at 3838 North Central Avenue, Suite 1500, Phoenix, Arizona 85012, was organized to participate in real estate joint ventures and other real estate related activities. SCM is a wholly-owned subsidiary of SunCor.

(5) Golf de Mexico, S.A. DE C.V. ("Golf de Mexico") -- a Mexican variable capital corporation having been incorporated on February 8, 1992 in Tijuana, Baja California, Mexico, and having its principal executive offices at 3838 North Central Avenue, Suite 1500, Phoenix, Arizona 85012, was organized to operate and manage the Real del Mar Golf Course in Mexico. Golf de Mexico has been inactive.

(6) SunCor Realty & Management Company ("SunCor Realty") -- (previously named Russell Ranch Development Company) an Arizona corporation having been incorporated on April 1, 1994 and having its principal executive offices at 3838 North Central Avenue, Suite 1500, Phoenix, Arizona 85012 was organized to participate in real estate management and other real estate related activities. SunCor Realty is a wholly-owned subsidiary of SunCor.

(7) Palm Valley Golf Club, Inc. ("Palm Valley Golf") -- an Arizona corporation having been incorporated on January 23, 1996 and having its principal executive offices at 3838 North Central Avenue, Suite 1500, Phoenix, Arizona 85012, was organized to hold title to the Palm Valley Golf Course. Palm Valley Golf is a wholly-owned subsidiary of SunCor.

(8) Rancho Viejo de Santa Fe, Inc. ("Rancho Viejo") -- a New Mexico corporation having been incorporated on March 18, 1996 and having its principal executive offices at 1590-B Pacheco Street, Santa Fe, New Mexico 87505, was organized to engage in real estate development in New Mexico. Rancho Viego is a wholly-owned subsidiary of SunCor.

(9) Ranchland Utility Company ("Ranchland") -- a New Mexico corporation having been incorporated on September 5, 1997 and having its principal executive offices at 1590-B Pacheco Street, Santa Fe, New Mexico 87505 is a waste water utility. Ranchland is a wholly-owned subsidiary of Rancho Viejo.

c. El Dorado Investment Company -- an Arizona corporation having been incorporated on July 27, 1983 and having its principal executive offices at 400 East Van Buren, Suite 800, Phoenix, Arizona 85004, is a wholly-owned subsidiary of Claimant engaged primarily in the acquisition and holding of stocks and securities of other companies for investment purposes.

2. A BRIEF DESCRIPTION OF THE PROPERTIES OF CLAIMANT AND EACH OF ITS SUBSIDIARY PUBLIC UTILITY COMPANIES USED FOR THE GENERATION, TRANSMISSION AND DISTRIBUTION OF ELECTRIC ENERGY FOR SALE, OR FOR THE PRODUCTION, TRANSMISSION AND DISTRIBUTION OF NATURAL OR MANUFACTURED GAS, INDICATING THE LOCATION OF PRINCIPAL GENERATING PLANTS, TRANSMISSION LINES, PRODUCING FIELDS, GAS MANUFACTURING PLANTS AND ELECTRIC AND GAS DISTRIBUTION FACILITIES, INCLUDING ALL SUCH PROPERTIES WHICH ARE OUTSIDE THE STATE IN WHICH CLAIMANT AND ITS SUBSIDIARIES ARE ORGANIZED AND ALL TRANSMISSION OR PIPELINES WHICH DELIVER OR RECEIVE ELECTRIC ENERGY OR GAS AT THE BORDERS OF SUCH STATE.

Neither the Claimant nor any of its subsidiaries own property used for the production, transmission and distribution of natural or manufactured gas. APS, a "public utility company" as that term is defined in the Public Utility Holding Company Act of 1935, is the only one of Claimant's subsidiaries that owns property used for the generation, transmission and distribution of electric energy for sale.

Exhibit D attached hereto shows the location of APS' major generating plants (including those owned jointly with others), principal transmission lines (including those operated for others) and interconnections of transmission lines with out-of-state utilities at state lines. All of such facilities, except the Four Corners Generating Station ("Four Corners"), and all of APS' distribution facilities, are located within the State of Arizona. Four Corners is a mine-mouth power plant, located in the northwest corner of New Mexico, near the city of Farmington, approximately 40 miles east of the Arizona-New Mexico border.

APS' present generating facilities have an accredited capacity aggregating 3,986,900 kilowatts, comprised as follows:

	CAPACITY (kW)
Coal:	
Units 1, 2 and 3 at Four Corners, aggregating	560,000
15% owned Units 4 and 5 at Four Corners, representing	222,000
Units 1, 2, and 3 at the Cholla Plant, aggregating	615,000
14% owned Units 1, 2 and 3 at the Navajo Plant, representing	315,000
	1,712,000
Gas or Oil:	
Two steam units at Ocotillo, two steam units at Saguaro and one steam unit at Yucca, aggregating	435,000(1)
Eleven combustion turbine units, aggregating	493,000
Three combined cycle units, aggregating	255,000
	1,183,000
Nuclear:	
29.1 % owned or leased Units 1, 2 and 3 at Palo Verde, representing	1,086,300
Other	5,600

(1) West Phoenix steam units (108,300 kw) are currently mothballed.

APS' transmission facilities consist of approximately 5,268 pole miles of overhead lines and approximately 23 miles of underground lines, all of which are located within the State of Arizona. APS' distribution facilities consist of approximately 11,444 pole miles of overhead lines and approximately 10,110 miles of underground lines, all of which are located within the State of Arizona.

3. THE FOLLOWING INFORMATION FOR THE LAST CALENDAR YEAR WITH RESPECT TO CLAIMANT AND EACH OF ITS SUBSIDIARY PUBLIC UTILITY COMPANIES (DATA IS NOT CURRENTLY MAINTAINED IN A FORMAT IDENTIFYING THE STATE IN WHICH THE SALES AND PURCHASES ARE MADE OR THE AMOUNT OF THEIR ASSOCIATED REVENUES OR EXPENSES.):

a. NUMBER OF KWH OF ELECTRIC ENERGY SOLD (AT RETAIL OR WHOLESALE), AND MCF. OF NATURAL OR MANUFACTURED GAS DISTRIBUTED AT RETAIL.

CLAIMANT	APS
None	30,780,474,000 kwh of electric energy sold at wholesale or retail
	0 Mcf. of natural or manufactured gas distributed at wholesale or retail

b. NUMBER OF KWH OF ELECTRIC ENERGY AND MCF. OF NATURAL OR MANUFACTURED GAS DISTRIBUTED AT RETAIL OUTSIDE THE STATE IN WHICH EACH SUCH COMPANY IS ORGANIZED.

CLAIMANT	APS
None	62,591,000 kwh of electric energy was distributed at retail outside Arizona.
	0 Mcf. of natural or manufactured gas distributed at retail outside Arizona

c. NUMBER OF KWH OF ELECTRIC ENERGY AND MCF. OF NATURAL OR MANUFACTURED GAS SOLD AT WHOLESALE OUTSIDE THE STATE IN WHICH EACH SUCH COMPANY IS ORGANIZED, OR AT THE STATE LINE.

CLAIMANT	APS
None	976,200 kwh of electric energy was sold at wholesale (to meet wholesale native load) outside Arizona or at state line. Data on wholesale non-native load is not currently maintained in this format.
	0 Mcf. of natural or manufactured gas sold at wholesale (to meet wholesale native load) outside Arizona or at state line.

d. NUMBER OF KWH OF ELECTRIC ENERGY AND MCF. OF NATURAL OR MANUFACTURED GAS PURCHASED OUTSIDE THE STATE IN WHICH EACH SUCH COMPANY IS ORGANIZED OR AT THE STATE LINE.

CLAIMANT	APS
None	0 kwh of electric energy was purchased outside Arizona or at state line. Data is not currently maintained in this format.
	19,380,577 Mcf. of natural or manufactured gas (used for generation) purchased outside Arizona or at state line.

4. THE FOLLOWING INFORMATION FOR THE REPORTING PERIOD WITH RESPECT TO CLAIMANT AND EACH INTEREST IT HOLDS DIRECTLY OR INDIRECTLY IN AN EWG OR A FOREIGN UTILITY COMPANY, STATING MONETARY AMOUNTS IN UNITED STATES DOLLARS:

The Claimant holds no interest, direct or indirect, in an EWG or a foreign utility company.

a. NAME, LOCATION, BUSINESS ADDRESS AND DESCRIPTION OF THE FACILITIES USED BY THE EWG OR FOREIGN UTILITY COMPANY FOR THE GENERATION, TRANSMISSION AND DISTRIBUTION OF ELECTRIC ENERGY FOR SALE OR FOR THE DISTRIBUTION AT RETAIL OF NATURAL OR MANUFACTURED GAS.

Not applicable.

b. NAME OF EACH SYSTEM COMPANY THAT HOLDS AN INTEREST IN SUCH EWG OR FOREIGN UTILITY COMPANY; AND DESCRIPTION OF THE INTEREST HELD.

Not applicable.

c. TYPE AND AMOUNT OF CAPITAL INVESTED, DIRECTLY OR INDIRECTLY, BY THE HOLDING COMPANY CLAIMING EXEMPTION; ANY DIRECT OR INDIRECT GUARANTEE OF THE SECURITY OF THE EWG OR FOREIGN UTILITY COMPANY BY THE HOLDING COMPANY CLAIMING EXEMPTION; AND ANY DEBT OR OTHER FINANCIAL OBLIGATION FOR WHICH THERE IS RECOURSE, DIRECTLY OR INDIRECTLY, TO THE HOLDING COMPANY CLAIMING EXEMPTION OR ANOTHER SYSTEM COMPANY, OTHER THAN THE EWG OR FOREIGN UTILITY COMPANY.

Not applicable.

d. CAPITALIZATION AND EARNINGS OF THE EWG OR FOREIGN UTILITY COMPANY DURING THE REPORTING PERIOD.

Not applicable.

e. IDENTIFY ANY SERVICE, SALES OR CONSTRUCTION CONTRACT(S) BETWEEN THE EWG OR FOREIGN UTILITY COMPANY AND A SYSTEM COMPANY, AND DESCRIBE THE SERVICES TO BE RENDERED OR GOODS SOLD AND FEES OR REVENUES UNDER SUCH AGREEMENT(S).

Not applicable.

EXHIBIT A

A CONSOLIDATING STATEMENT OF INCOME AND SURPLUS OF THE CLAIMANT AND ITS SUBSIDIARY COMPANIES FOR THE LAST CALENDAR YEAR, TOGETHER WITH A CONSOLIDATING BALANCE SHEET OF CLAIMANT AND ITS SUBSIDIARY COMPANIES AS OF THE CLOSE OF SUCH CALENDAR YEAR.

Exhibit A hereto includes consolidating statements of income and consolidating balance sheets for the Claimant and the following of its subsidiaries: Arizona Public Service Company, SunCor Development Company and El Dorado Investment Company. Subsidiaries have been consolidated for financial reporting purposes in accordance with Statement of Financial Accounting Standards No. 94, CONSOLIDATION OF ALL MAJORITY-OWNED SUBSIDIARIES. Also included are consolidating statements of income and consolidating balance sheets for SunCor Development Company and its subsidiaries.

EXHIBIT B FINANCIAL DATA STATEMENT

If, at the time a report on this form is filed, the registrant is required to submit this report and any amendments thereto electronically via EDGAR, the registrant shall furnish a Financial Data Schedule. The Schedule shall set forth the financial and other data specified below that are applicable to the registrant on a consolidated basis.

1. Total Assets.

2. Total Operating Revenues.

3. Net Income.

See Exhibit B hereto.

EXHIBIT C

An organizational chart showing the relationship of each EWG or foreign utility company to associate companies in the holding-company system.

Not applicable.

EXHIBIT D

In accordance with Item 304 of Regulation S-T of the Securities Exchange Act of 1934, APS' Service Territory map contained as Exhibit D to this Form U-3A-2 is a map of the State of Arizona showing APS' service area, the location of its major power plants and principal transmission lines, and the location of transmission lines operated by APS for others. The major power plants shown on such map are the Navajo Generating Station located in Coconino County, Arizona; the Four Corners Power Plant located near Farmington, New Mexico; the Cholla Power Plant, located in Navajo County, Arizona; the Yucca Power Plant, located near Yuma, Arizona; and the Palo Verde Nuclear Generating Station, located about 55 miles west of Phoenix, Arizona (each of which plants is reflected on such map as being jointly owned with other utilities), as well as the Ocotillo Power Plant and West Phoenix Power Plant, each located near Phoenix, Arizona, and the Saguaro Power Plant, located near Tucson, Arizona. APS' major transmission lines shown on such map are reflected as running between the power plants named above and certain major cities in the State of Arizona. The transmission lines operated for others shown on such map are reflected as running from the Four Corners Plant through a portion of northern Arizona to the California border.

The above-named Claimant has caused this statement to be duly executed on its behalf by its authorized officer on this 1st day of March, 1999.

PINNACLE WEST CAPITAL CORPORATION
(Name of Claimant)

By Michael V. Palmeri

Michael V. Palmeri
Treasurer

[CORPORATE SEAL]

Attest:

Suzanne Debes

Suzanne Debes
Associate Secretary

Name, title and address of officer to whom notices and correspondence concerning this statement should be addressed:

MICHAEL V. PALMERI (Name) TREASURER (Title)

400 EAST VAN BUREN, SUITE 700, PHOENIX, ARIZONA 85004
(Address)

EXHIBIT B Financial Data Schedule

The Claimant submits the following consolidated financial information:

1.	Total Assets:	$6,824,546,000
2.	Total Operating Revenues:	$2,130,586,000
3	Net Income:	$242,892,000

PINNACLE WEST CAPITAL CORPORATION
CONSOLIDATING BALANCE SHEET (UNAUDITED)
December 31, 1998
(THOUSANDS OF DOLLARS)

	PWCC	APS	SUNCOR	ELDO	*ELIMINATIONS AND ADJUSTING ENTRIES* DEBIT	CREDIT	TOTAL
ASSET							
CURRENT ASSETS							
Cash and cash equivalents	$ 8,833	$ 5,558	$ 4,332	$ 1,815	$ --	$ --	$ 20,538
Customer and other receivables - net	1,679	227,487	5,400	1,000	--(n)	1,690(b)	233,876
Accrued utility revenue		67,740					67,740
Materials and supplies		69,074					69,074
Fossil fuel		13,978					13,978
Deferred income taxes	--	3,999	3,975	--		3,975(o)	3,999
Other current assets	619	26,695	21,287	33		1,040(c)	47,594
Total current assets	11,131	414,531	34,994	2,848	--	6,705	456,799
INVESTMENTS AND OTHER ASSETS							
Real estate investments net (cap interest)			330,622		6,161(f)	5,762(e)	331,021
Other assets	2,333,482	183,549	9,018	24,295		2,313,782(a,f,h)	236,562
Total investments and other	2,333,482	183,549	339,640	24,295	6,161	2,319,544	567,583
UTILITY PLANT							
Electric plant in service and held for future use		7,265,604					7,265,604
Less accumulated depreciation and amortization		2,814,762					2,814,762
Total Utility Plant		4,450,842					4,450,842
Nuclear Fuel, net of amortizaton		51,078					51,078
Construction work in progress		228,643					228,643
Net Utility Plant		4,730,563					4,730,563
DEFERRED DEBITS							
Deferred income taxes			33,228			33,228(o)	--
Regulatory asset for income taxes		400,795					400,795
Rate synchronization cost deferrals		303,660					303,660
Other deferred debits	5,120	360,201	4,937	--	8(h)	5,120(j)	365,146
Total deferred debits	5,120	1,064,656	38,165	--	8	38,348	1,069,601
TOTAL ASSETS	$2,349,733	$6,393,299	$412,799	$ 27,143	$ 6,169	$2,364,597	$6,824,546

PINNACLE WEST CAPITAL CORPORATION
CONSOLIDATING BALANCE SHEET (UNAUDITED)
December 31, 1998
(THOUSANDS OF DOLLARS)

LIABILITIES AND EQUITY							
CURRENT LIABILITIES							
Accounts payable	$ 1,785	$ 145,139	$ 8,847	$ 34	$ 5(i)		$ 155,800
Accrued taxes		59,827	--	8		2,685(l,k)	62,520
Accrued interest	199	31,218	449	--			31,866
Dividend payable	--	--			--(d)		--
Short-term borrowings	--	--			--(m)		--
Commerical paper, net	--	178,830					178,830
Current maturities of long-term debt		154,378	3,667				158,045
Customer Deposits		26,815	1,695				28,510
Other current liabilities	3,311	16,755	629	195	6,258(b,c,g)		14,632
Total current liabilities	5,295	612,962	15,287	237	6,263	2,685	630,203
NON-CURRENT LIABILITIES							
Long-term debt less current maturities	92,000	1,886,540	80,421				2,058,961
DEFERRED CREDITS AND OTHER							
Deferred income taxes	71,412	1,312,007			39,883(k,o)		1,343,536
Deferred investment tax credit		32,465			5,120(j)		27,345
Unamortized gain-sale of utility plant		77,787					77,787
Other deferred credits	17,675	400,542	6,377			3,528(g)	428,122
Total deferred credits	89,087	1,822,801	6,377	--	45,003	3,528	1,876,790
COMMITMENTS AND CONTINGENCIES (NOTE)							
MINORITY INTERESTS:							
Non-Redeemable preferred stock of APS		85,840					85,840
Redeemable preferred stock of APS		9,401					9,401
Joint Ventures of SunCor			5,762		5,762(e)		--
COMMON STOCK EQUITY:							
Common stock	2,023,744	1,373,787	376,391	38,046	2,261,325(a)		1,550,643
Accumulated deficit	139,607	601,968	(71,439)	(11,140)	46,288(a)		612,708
Total	2,163,351	1,975,755	304,952	26,906	2,307,613		2,163,351
TOTAL LIABILITIES AND EQUITY	$2,349,733	$6,393,299	$ 412,799	$ 27,143	$2,364,641	$ 6,213	$6,824,546

PINNACLE WEST CAPITAL CORPORATION
CONSOLIDATING BALANCE SHEET
ELIMINATING AND ADJUSTING ENTRIES

		DEBITS	CREDITS
(a)	Common stock	$2,261,325	
	Accumulated earnings	46,288	
	Other investments		$2,307,613

To eliminate PNW investment in subsidiaries

	Common Stock	Earnings/ Dividends	Total
APS	$1,846,888	$ 128,867	$1,975,755
SunCor	376,391	(71,439)	304,952
El Dorado	38,046	(11,140)	26,906
Total	$2,261,325	$ 46,288	$2,307,613

(b)	Other current liabilities	$ 1,690	
	Customer and other receivables - net		1,690

To eliminate intercompany receivables/payables

	A/R PNW	A/P Subs Books
APS	$1,276	$1,276
SunCor	225	225
El Dorado	189	189
Total	$1,690	$1,690

(c)	Other current liabilities	$1,040	
	Other current assets		$1,040

To eliminate PNW payable to APS

(d)	Dividends Payable	--	
	Customer and other receivable - net		--

To eliminate APS Dividend to PNW

(e)	Minority interest	$5,762	
	Real estate investments - net		$5,762

To eliminate minority interest of SunCor JV partners

(f)	Real estate investments - net	$6,161	
	Other - assets		$6,161

To reclass PNW capitalized interest related to SunCor

(g)	Other current liabilities	$3,528	
	Other deferred credits		$3,528

To reclass PNW deferred comp to long-term

(h)	Other deferred debits	$8	
	Other - assets		$8

To reclass PNW unamortized debt to long-term

(i)	Accounts payable	$5	
	Accrued taxes		$5

To reclass PNW property tax

(j)	Deferred investment tax credit	$5,120	
	Other deferred debits		$5,120

To reclass PNW ITC from Deferred taxes to Deferred ITC

(k)	Other deferred debits	$2,680	
	Accrued taxes		$2,680

To reclass PNW accrued taxes

(o)	Deferred income taxes-current portion		$3,975
	Deferred income taxes-noncurrent portion		33,228
	Deferred income taxes	$37,203	

To eliminate Suncor deferred tax asset and PNW deferred tax liability.

PINNACLE WEST CAPITAL CORPORATION
CONSOLIDATING INCOME STATEMENT (UNAUDITED)
FOR THE PERIODS ENDED DECEMBER 31, 1998
(THOUSANDS OF DOLLARS)

	PWCC	APS	SUNCOR	ELDO	ADJUSTMENTS & ELIMINATIONS DEBIT	ADJUSTMENTS & ELIMINATIONS CREDIT	TOTAL
OPERATING REVENUES:							
Electric	$ --	$2,006,398	$ --	$ --	$ --	$ --	$2,006,398
Real Estate			124,188				124,188
Total	--	2,006,398	124,188	--	--	--	2,130,586
FUEL EXPENSES:							
Fuel for electric generation		231,967					231,967
Purchased power		305,534					305,534
Total	--	537,501	--	--	--	--	537,501
OPERATING EXPENSES:							
Utility operations and maintenance		414,041					414,041
Real estate operations			116,216		731(b)	1,616(d)	115,331
Depreciation and amortization	209	376,574	2,896	--			379,679
Taxes other than income taxes		115,264			1,642(c,d)		116,906
Total	209	905,879	119,112	--	2,373	1,616	1,025,957
OPERATING INCOME	(209)	563,018	5,076	--	(2,373)	(1,616)	567,128
OTHER INCOME (DEDUCTIONS):							
Interest on long-term debt	(9,874)	(137,214)	(6,648)	--			(153,736)
Other interest	(673)	(15,061)	--	--		325(e)	(15,409)
Capitalized interest		16,263	2,333				18,596
Preferred stock dividend requirements		(9,703)					(9,703)
Other, net	292,897	(12,303)	6,758	7,616	295,116(a,e)	757(b,c)	609
Total	282,350	(158,018)	2,443	7,616	295,116	1,082	(159,643)
INCOME BEFORE INCOME TAXES	282,141	405,000	7,519	7,616	297,489	(534)	407,485
Income Tax Expense (Benefit)	39,249	159,456	(37,200)	3,088			164,593
NET INCOME (LOSS)	$242,892	$ 245,544	$ 44,719	$ 4,528	$ 297,489	$ (534)	$ 242,892

PINNACLE WEST CAPITAL CORPORATION
CONSOLIDATING INCOME STATEMENT
ELIMINATING ENTRIES

(a)	Other - net (Subs income)		$ 294,791		
	Retained Earnings				$ 294,791

To eliminate PWCC Equity in earnings from subsidiaries

	PWCC
APS	$245,544
SunCor	44,719
El Dorado	4,528
Total	$294,791

(b)	Real Estate Operations		$ 731		
	Interest Expense (PWCC)				$ 731

To reclass Capitalized Interest for SunCor Land Sales

(c)	Taxes other than income taxes		$ 26		
	Other - net				$ 26

To reclass PNW property taxes

(d)	Taxes other than income taxes		$ 1,616		
	Real estate operations				$ 1,616

To reclass SunCor property taxes

(e)	Other, net (El Dorado interest income)		$ 325		
	Other interest				$ 325

To eliminate interest on ELD loan to PNW

SUNCOR DEVELOPMENT COMPANY
CONSOLIDATED BALANCE SHEET (UNAUDITED)
FOR THE MONTH ENDED DECEMBER 31, 1998

	ACCOUNT DESCRIPTION	SUNCOR CORPORATE	LPSCO	SASI	SMLP	PVGC
ASSETS:						
	CURRENT ASSETS					
	CASH AND SHORT TERM INVESTMENTS	$ 1,019,737	$430,710	$ 395,891	$ 575,390	$ (1,126)
1	ACCOUNTS RECEIVABLE	266,375	141,342	66,609	1,224,420	20,757
	INTERCOMPANY ACCOUNTS:					
1	SASI	0				
1	LPSCO	21,391				
1	SMLP	27,761				
1	PVGC	0				4,060,675
1	WWOS	48,503				
1	GOLDEN HERITAGE - GENERAL	767,728				
1	SCM-GENERAL	4,981,309				
1	HOMEBUILDING I/C INTEREST	2,592,637				
1	HOMEBUILDING CASH ADVANCES	13,778,208				
	COMMERCIAL - GENERAL	0				
1	SUNRIDGE - DEVELOPMENT	38,671				
1	SUNRIDGE - GOLF	218,991				
1	SEDONA - DEVELOPMENT	43,125				
1	SEDONA - GOLF	152,365				
1	WIGWAM RESORT	179,892				
1	INTEREST RECEIVABLE	371,731				
	NOTES RECEIVABLE	2,174,874			0	
2	INVENTORIES					63,252
2	PREPAID EXPENSES	115,158	4,664			46,108
	HOME INVENTORY	6,888				
	DEFERRED INCOME TAX	3,974,512				
	TOTAL CURRENT ASSETS	29,779,855	576,716	462,600	1,799,810	4,189,667

	ACCOUNT DESCRIPTION	HOMES	PV	WWOS	KABUTO JV	COMM.
ASSETS:						
	CURRENT ASSETS					
	CASH AND SHORT TERM INVESTMENTS	$ 926,993	$1,300,540	$ 193,117	$ 174	$ (416,346)
1	ACCOUNTS RECEIVABLE	269,382		173,920		428,734
	INTERCOMPANY ACCOUNTS:					
1	SASI					
1	LPSCO					
1	SMLP					
1	PVGC					
1	WWOS					
1	GOLDEN HERITAGE - GENERAL	667,368				
1	SCM-GENERAL	(4,981,309)				
1	HOMEBUILDING I/C INTEREST	(2,592,637)				
1	HOMEBUILDING CASH ADVANCES					
	COMMERCIAL - GENERAL					
1	SUNRIDGE - DEVELOPMENT					
1	SUNRIDGE - GOLF					
1	SEDONA - DEVELOPMENT					
1	SEDONA - GOLF					
1	WIGWAM RESORT					
1	INTEREST RECEIVABLE		10,407			16,325
	NOTES RECEIVABLE					12,120
2	INVENTORIES					36,162
2	PREPAID EXPENSES		1,014			11,850
	HOME INVENTORY	23,553,307				
	DEFERRED INCOME TAX					
	TOTAL CURRENT ASSETS	17,843,105	1,311,961	367,037	174	88,845

	ACCOUNT DESCRIPTION	H HILLS	R VIEJO	C. CANYON	REF	ELIMINATIONS DEBIT	REF	CREDIT
ASSETS:								
	CURRENT ASSETS							
	CASH AND SHORT TERM INVESTMENTS	$ 1,892	$ (96,606)	$ 1,445		$ --		$ --
1	ACCOUNTS RECEIVABLE						J,Q	315,272
	INTERCOMPANY ACCOUNTS:							
1	SASI							0
1	LPSCO						H	21,391
1	SMLP				J		0 J	27,761
1	PVGC						N	4,060,675
1	WWOS				Q		0 Q	48,503
1	GOLDEN HERITAGE - GENERAL						A	1,432,265
1	SCM-GENERAL				A	4,981,309	A	4,981,309
1	HOMEBUILDING I/C INTEREST				C	2,592,637	C	2,592,637
1	HOMEBUILDING CASH ADVANCES						B	12,777,915
	COMMERCIAL - GENERAL							
1	SUNRIDGE - DEVELOPMENT							
1	SUNRIDGE - GOLF							
1	SEDONA - DEVELOPMENT							
1	SEDONA - GOLF							
1	WIGWAM RESORT							
1	INTEREST RECEIVABLE						P	97,398
	NOTES RECEIVABLE		0					
2	INVENTORIES			12,480				
2	PREPAID EXPENSES			1,839				
	HOME INVENTORY						E	2,565,923
	DEFERRED INCOME TAX							
	TOTAL CURRENT ASSETS	1,892	(96,606)	15,763		7,573,946		28,921,050

	ACCOUNT DESCRIPTION	CONSOLIDATED
ASSETS:		
	CURRENT ASSETS	
	CASH AND SHORT TERM INVESTMENTS	$ 4,331,912
1	ACCOUNTS RECEIVABLE	2,276,268
	INTERCOMPANY ACCOUNTS:	
1	SASI	0
1	LPSCO	0
1	SMLP	0
1	PVGC	0
1	WWOS	0
1	GOLDEN HERITAGE - GENERAL	2,831
1	SCM-GENERAL	0
1	HOMEBUILDING I/C INTEREST	0
1	HOMEBUILDING CASH ADVANCES	292
	COMMERCIAL - GENERAL	0
1	SUNRIDGE - DEVELOPMENT	38,671
1	SUNRIDGE - GOLF	218,991
1	SEDONA - DEVELOPMENT	43,125
1	SEDONA - GOLF	152,365
1	WIGWAM RESORT	179,892
1	INTEREST RECEIVABLE	301,065
	NOTES RECEIVABLE	2,186,994
2	INVENTORIES	111,894
2	PREPAID EXPENSES	180,632
	HOME INVENTORY	20,994,272
	DEFERRED INCOME TAX	3,974,512
	TOTAL CURRENT ASSETS	34,993,716

	ACCOUNT DESCRIPTION	SUNCOR CORPORATE	LPSCO	SASI	SMLP	PVGC
	LONG-TERM ASSETS					
	DEVELOPMENT PROJECTS					
	CORAL CANYON					
	HIDDEN HILLS					
	RANCHO VIEJO					
	PALM VALLEY					
	LITCHFIELD GREENS					
	VILLAGE OF LITCHFIELD GREENS					
	SCOTTSDALE MOUNTAIN				5,597,906	
	MARKETPLACE - AUTOPLEX					
	TATUM RANCH	7,011,475				
	TALAVI					
	WIGWAM OUTLET STORES					
	GOLDEN HERITAGE LAND					
	BILTMORE ESTATES	0				
	OTHER COMMERCIAL LAND					
	EQUITY INVESTMENTS:					
	EQUITY IN CTRPT ASSOC-LLP					
	INVEST IN KYRENE ASSOCIATES LLC					
	INVEST IN PV APARTMENTS (I & II)					
	INVESTMENT IN SUNRIDGE CANYON LLC	9,652,389				
	INVESTMENT IN SEDONA GOLF LC	3,589,437				
	INVESTMENT IN PLUMCOR REALTY LLC					
	INVEST IN TALAVI ASSOCIATES LLC					
	INVESTMENT IN WESTWORLD GOLF	782,907				
	CONSOLIDATED ELIMINATING ENTITIES:					
	INVEST IN KABUTO/SUNCOR JV	5,882,342				
	INVESTMENT IN WIGWAM OUTLET LLC					
	INVEST IN SCOTTS MTN LTD PART	5,245,299				
	INVEST IN GOLDEN HERITAGE	1,154,335				
	GOLDEN HERITAGE DUE DILIGENCE	0				
	INVESTMENT IN SCM	525,943				
5	INVESTMENT IN LPSCO	12,173,458				
	INVESTMENT IN SASI	0				
	INVESTMENT IN PALM VALLEY	167,221,252				
	INVESTMENT IN PALM VALLEY GOLF	6,231,352				
	PALM VALLEY GOLF CONTRIB. CAP	(4,060,675)				
	INVESTMENT IN RANCHO VIEJO	8,674,183				
	INVESTMENT IN HIDDEN HILLS	1,170,838				
	INVESTMENT IN CORAL CANYON	481,241				
	PROJECT 2000:					
	INVESTMENT IN FIDDLESTICKS-SCOTTS	(603,562)				
	INVESTMENT IN FIDDLESTICKS-TEMPE	1,623,517				
	INVESTMENT IN FUNTASTICKS	2,334,403				
	INVESTMENT IN GENERAL COMM OPS	79,255,821				
	INVESTMENT IN PV MARKETPLACE	1,406,129				
	INVESTMENT IN PV PAVILIONS	899,849				
	INVESTMENT IN PV CROSSING	311,587				
	INVESTMENT IN AUTOPLEX	(574,137)				
	INVESTMENT IN TALAVI	(139,299)				
	INVESTMENT IN METROCENTER	253,727				
	INVESTMENT IN RESTORATION PLACE	(65,725)				
	INVESTMENT IN LITCHFIELD PARK OPS	73,203				
	INVESTMENT IN LP PROF. PLAZA	(18,428)				
	INVESTMENT IN WWOS LLC	(11,397)				
	INVESTMENT IN APS PROPERTIES	(126,084)				
	COMMERCIAL PROPERTIES					5,294,782
	LONG-TERM NOTES RECEIVABLE	5,964,889				
	SDC PHASE I LAND NOTE TO WWOS	1,304,153				
	SDC PAYOFF OF WWOS RLC	10,000,000				
	SDC LOAN TO LPSCO	300,000				
	PROPERTY & EQUIPMENT, NET	785,336		36,696		142,635
3	DEFERRED ASSETS	2,696,758	1,195,557			202,691
	DEFERRED INCOME TAXES	33,225,488				
	WATER & SEWER UTILITY PROP, NET		13,503,454			
3	DEPOSITS					
	TOTAL LONG-TERM ASSETS	364,632,003	14,699,011	36,696	5,597,906	5,640,108
	TOTAL ASSETS	$394,411,858	$ 15,275,727	$ 499,296	$ 7,397,716	$ 9,829,775

	ACCOUNT DESCRIPTION	HOMES	PV	WWOS	KABUTO JV	COMM.
	LONG-TERM ASSETS					
	DEVELOPMENT PROJECTS					
	CORAL CANYON					
	HIDDEN HILLS					
	RANCHO VIEJO					
	PALM VALLEY		164,717,178			16,567,774
	LITCHFIELD GREENS		943,106			
	VILLAGE OF LITCHFIELD GREENS				12,705,211	
	SCOTTSDALE MOUNTAIN					
	MARKETPLACE - AUTOPLEX					12,962,803
	TATUM RANCH					
	TALAVI					2,414,265
	WIGWAM OUTLET STORES			16,232,891		
	GOLDEN HERITAGE LAND	1,393,876				
	BILTMORE ESTATES					
	OTHER COMMERCIAL LAND					3,500,641
	EQUITY INVESTMENTS:					
	EQUITY IN CTRPT ASSOC-LLP					23,472,509
	INVEST IN KYRENE ASSOCIATES LLC					1,440,528
	INVEST IN PV APARTMENTS (I & II)		936,291			
	INVESTMENT IN SUNRIDGE CANYON LLC					
	INVESTMENT IN SEDONA GOLF LC					
	INVESTMENT IN PLUMCOR REALTY LLC					120,000
	INVEST IN TALAVI ASSOCIATES LLC					2,842,332
	INVESTMENT IN WESTWORLD GOLF					
	CONSOLIDATED ELIMINATING ENTITIES:					
	INVEST IN KABUTO/SUNCOR JV					
	INVESTMENT IN WIGWAM OUTLET LLC					3,807,232
	INVEST IN SCOTTS MTN LTD PART					
	INVEST IN GOLDEN HERITAGE					
	GOLDEN HERITAGE DUE DILIGENCE					
	INVESTMENT IN SCM					
5	INVESTMENT IN LPSCO		373,781			

	INVESTMENT IN SASI					
	INVESTMENT IN PALM VALLEY					
	INVESTMENT IN PALM VALLEY GOLF					
	PALM VALLEY GOLF CONTRIB. CAP					
	INVESTMENT IN RANCHO VIEJO					
	INVESTMENT IN HIDDEN HILLS					
	INVESTMENT IN CORAL CANYON					
	PROJECT 2000:					
	INVESTMENT IN FIDDLESTICKS-SCOTTS					
	INVESTMENT IN FIDDLESTICKS-TEMPE					
	INVESTMENT IN FUNTASTICKS					
	INVESTMENT IN GENERAL COMM OPS					
	INVESTMENT IN PV MARKETPLACE					
	INVESTMENT IN PV PAVILIONS					
	INVESTMENT IN PV CROSSING					
	INVESTMENT IN AUTOPLEX					
	INVESTMENT IN TALAVI					
	INVESTMENT IN METROCENTER					
	INVESTMENT IN RESTORATION PLACE					
	INVESTMENT IN LITCHFIELD PARK OPS					
	INVESTMENT IN LP PROF. PLAZA					
	INVESTMENT IN WWOS LLC					
	INVESTMENT IN APS PROPERTIES					
	COMMERCIAL PROPERTIES					18,007,355
	LONG-TERM NOTES RECEIVABLE		187,817			265,654
	SDC PHASE I LAND NOTE TO WWOS					
	SDC PAYOFF OF WWOS RLC					
	SDC LOAN TO LPSCO					
	PROPERTY & EQUIPMENT, NET	1,388,591	99,108	71,783		
3	DEFERRED ASSETS		169,620	157,599		441,233
	DEFERRED INCOME TAXES					
	WATER & SEWER UTILITY PROP, NET					
3	DEPOSITS	72,915				
	TOTAL LONG-TERM ASSETS	2,855,382	167,426,901	16,462,273	12,705,211	85,842,327
	TOTAL ASSETS	20,698,487	$ 168,738,862	$ 16,829,310	$ 12,705,385	$ 85,931,172

					ELIMINATIONS		
	ACCOUNT DESCRIPTION	H HILLS	R VIEJO	C. CANYON	REF	DEBIT	REF	CREDIT
	LONG-TERM ASSETS							
	DEVELOPMENT PROJECTS							
	CORAL CANYON			465,261				
	HIDDEN HILLS	1,199,790						
	RANCHO VIEJO		9,258,472					
	PALM VALLEY							
	LITCHFIELD GREENS							
	VILLAGE OF LITCHFIELD GREENS							
	SCOTTSDALE MOUNTAIN							
	MARKETPLACE - AUTOPLEX							
	TATUM RANCH							
	TALAVI							
	WIGWAM OUTLET STORES							
	GOLDEN HERITAGE LAND							
	BILTMORE ESTATES							
	OTHER COMMERCIAL LAND							
	EQUITY INVESTMENTS:							
	EQUITY IN CTRPT ASSOC-LLP							
	INVEST IN KYRENE ASSOCIATES LLC							
	INVEST IN PV APARTMENTS (I & II)							
	INVESTMENT IN SUNRIDGE CANYON LLC							
	INVESTMENT IN SEDONA GOLF LC							
	INVESTMENT IN PLUMCOR REALTY LLC							
	INVEST IN TALAVI ASSOCIATES LLC							
	INVESTMENT IN WESTWORLD GOLF							
	CONSOLIDATED ELIMINATING ENTITIES:							
	INVEST IN KABUTO/SUNCOR JV						R	8,853,122
	INVESTMENT IN WIGWAM OUTLET LLC				O	18,539,382	O	23,340,125
	INVEST IN SCOTTS MTN LTD PART				I	15,730,119	I	20,999,080
	INVEST IN GOLDEN HERITAGE					0	D	1,154,335
	GOLDEN HERITAGE DUE DILIGENCE							
	INVESTMENT IN SCM						D	525,943
5	INVESTMENT IN LPSCO						F	11,925,668
	INVESTMENT IN SASI				L	650,000	L	1,023,781
	INVESTMENT IN PALM VALLEY					0	V	167,221,252
	INVESTMENT IN PALM VALLEY GOLF						M	6,231,352
	PALM VALLEY GOLF CONTRIB. CAP				N	4,060,675		
	INVESTMENT IN RANCHO VIEJO				U	85,702	U	8,759,885
	INVESTMENT IN HIDDEN HILLS				T	3,070	T	1,173,907
	INVESTMENT IN CORAL CANYON						W	481,241
	PROJECT 2000:							
	INVESTMENT IN FIDDLESTICKS-SCOTTS				S	2,426,077	S	1,822,515
	INVESTMENT IN FIDDLESTICKS-TEMPE						S	1,623,517
	INVESTMENT IN FUNTASTICKS						S	2,334,403
	INVESTMENT IN GENERAL COMM OPS				S	0	S	79,255,821
	INVESTMENT IN PV MARKETPLACE						S	1,406,129
	INVESTMENT IN PV PAVILIONS						S	899,849
	INVESTMENT IN PV CROSSING				S	0	S	311,587
	INVESTMENT IN AUTOPLEX				S	574,137		
	INVESTMENT IN TALAVI				S	139,299		
	INVESTMENT IN METROCENTER						S	253,727
	INVESTMENT IN RESTORATION PLACE				S	65,725		
	INVESTMENT IN LITCHFIELD PARK OPS						S	73,203
	INVESTMENT IN LP PROF. PLAZA				S	18,428	S	0
	INVESTMENT IN WWOS LLC				S	11,397	S	0
	INVESTMENT IN APS PROPERTIES				S	126,084	S	
	COMMERCIAL PROPERTIES							
	LONG-TERM NOTES RECEIVABLE							
	SDC PHASE I LAND NOTE TO WWOS						P	1,304,153
	SDC PAYOFF OF WWOS RLC						P	10,000,000
	SDC LOAN TO LPSCO						G	300,000
	PROPERTY & EQUIPMENT, NET		70,633	5,264				
3	DEFERRED ASSETS	0						
	DEFERRED INCOME TAXES							
	WATER & SEWER UTILITY PROP, NET							
3	DEPOSITS			150				
	TOTAL LONG-TERM ASSETS	1,199,790	9,329,105	470,675		42,430,095		351,274,594
	TOTAL ASSETS	$ 1,201,682	$ 9,232,499	$ 486,439		$ 50,004,040		$ 380,195,645

	ACCOUNT DESCRIPTION	CONSOLIDATED
	LONG-TERM ASSETS	
	DEVELOPMENT PROJECTS	
	CORAL CANYON	
	HIDDEN HILLS	465,261
	RANCHO VIEJO	1,199,790
	PALM VALLEY	9,258,472
	LITCHFIELD GREENS	181,284,952
	VILLAGE OF LITCHFIELD GREENS	943,106
	SCOTTSDALE MOUNTAIN	12,705,211
	MARKETPLACE - AUTOPLEX	5,597,906
	TATUM RANCH	12,962,803
	TALAVI	7,011,475
	WIGWAM OUTLET STORES	2,414,265
	GOLDEN HERITAGE LAND	16,232,891
	BILTMORE ESTATES	1,393,876
	OTHER COMMERCIAL LAND	0
	EQUITY INVESTMENTS:	3,500,641
	EQUITY IN CTRPT ASSOC-LLP	0
	INVEST IN KYRENE ASSOCIATES LLC	23,472,509
	INVEST IN PV APARTMENTS (I & II)	1,440,528
	INVESTMENT IN SUNRIDGE CANYON LLC	936,291
	INVESTMENT IN SEDONA GOLF LC	9,652,389
	INVESTMENT IN PLUMCOR REALTY LLC	3,589,437
	INVEST IN TALAVI ASSOCIATES LLC	120,000
	INVESTMENT IN WESTWORLD GOLF	2,842,332
	CONSOLIDATED ELIMINATING ENTITIES:	782,907
	INVEST IN KABUTO/SUNCOR JV	0
	INVESTMENT IN WIGWAM OUTLET LLC	(2,970,780)
	INVEST IN SCOTTS MTN LTD PART	(993,511)
	INVEST IN GOLDEN HERITAGE	(23,662)
	GOLDEN HERITAGE DUE DILIGENCE	0
	INVESTMENT IN SCM	0
5	INVESTMENT IN LPSCO	0
	INVESTMENT IN SASI	247,790
	INVESTMENT IN PALM VALLEY	0
	INVESTMENT IN PALM VALLEY GOLF	0
	PALM VALLEY GOLF CONTRIB. CAP	0
	INVESTMENT IN RANCHO VIEJO	0
	INVESTMENT IN HIDDEN HILLS	0
	INVESTMENT IN CORAL CANYON	0
	PROJECT 2000:	0
	INVESTMENT IN FIDDLESTICKS-SCOTTS	
	INVESTMENT IN FIDDLESTICKS-TEMPE	0
	INVESTMENT IN FUNTASTICKS	0
	INVESTMENT IN GENERAL COMM OPS	0
	INVESTMENT IN PV MARKETPLACE	0
	INVESTMENT IN PV PAVILIONS	0
	INVESTMENT IN PV CROSSING	0
	INVESTMENT IN AUTOPLEX	0
	INVESTMENT IN TALAVI	0
	INVESTMENT IN METROCENTER	0
	INVESTMENT IN RESTORATION PLACE	0
	INVESTMENT IN LITCHFIELD PARK OPS	0
	INVESTMENT IN LP PROF. PLAZA	0
	INVESTMENT IN WWOS LLC	0
	INVESTMENT IN APS PROPERTIES	0
	COMMERCIAL PROPERTIES	0
	LONG-TERM NOTES RECEIVABLE	23,302,137
	SDC PHASE I LAND NOTE TO WWOS	6,418,360
	SDC PAYOFF OF WWOS RLC	0
	SDC LOAN TO LPSCO	0
	PROPERTY & EQUIPMENT, NET	0
3	DEFERRED ASSETS	2,600,045
	DEFERRED INCOME TAXES	4,863,457
	WATER & SEWER UTILITY PROP, NET	33,225,488
3	DEPOSITS	13,503,454
		73,065
	TOTAL LONG-TERM ASSETS	378,052,887
	TOTAL ASSETS	$ 413,046,603

	ACCOUNT DESCRIPTION	SUNCOR CORPORATE	LPSCO	SASI	SMLP	PVGC
	LIABILITIES:					
	CURRENT LIABILITIES					
4	A/P & RETENTION	$ 198,218	$ 193,109	$ 19,428	$ 69,484	$ 35,838
4	ACCRUED LIABILITIES	2,083,844	226,417	38,726	104,121	73,731
	INTERCOMPANY ACCOUNTS:					
4	LPSCO - SDC		21,391			
4	SMLP - SDC				27,761	
4	SCM-SDC CASH ADVANCES 267					
4	GH-SDC INTERCO CAPITAL 265					
4	WWOS-SDC					
	INTEREST PAYABLE	443,916				
	S/T NOTES PAYABLE					
	$45 MILLION TERM LOAN	3,208,144				
	$55 MILLION RLC					
	GOLDEN HERITAGE (PEW)					
	TEXTRON LOAN - PVGC					
	DEF PROFIT & UNEARNED REVENUE	2,661,923		18,569	0	
	PWCC INTERCO PAYABLE	358,870				
	APS LAND INTERCO PAYABLE					
	CUSTOMER DEPOSITS					
	TOTAL CURRENT LIABILITIES	8,954,915	440,917	76,723	201,366	109,569
	LONG-TERM LIABILITIES					
	LONG-TERM NOTES PAYABLE					
	WWOS OWES SDC PH I LAND NOTE					
	WWOS RLC PAYOFF BY SDC					
	CORPORATE TERM NOTE	38,853,019				
	CORPORATE RLC	38,138,836				
	LPSCO OWES SDC		300,000			
	TEXTRON LOAN - PVGC					3,488,854
5	OTHER ACCRUED LIABILITIES	3,513,221	889,149	48,792		
5	DEFERRED TAXES		216,617			
5	LONG-TERM CUSTOMER DEPOSITS		586,162			
5	CONTRIB PROPERTY AIA		916,642			
	TOTAL L/T LIABILITIES	80,505,077	2,908,570	48,792	0	3,488,854
	TOTAL LIABILITIES	89,459,992	3,349,487	125,515	201,366	3,598,423
	MINORITY INTEREST					

	ACCOUNT DESCRIPTION	HOMES	PV	WWOS	KABUTO JV	COMM.
	LIABILITIES:					
	CURRENT LIABILITIES					
4	A/P & RETENTION	$ 2,714,754	$ 1,036,745	$ 578,516	$	$ 202,637
4	ACCRUED LIABILITIES	(5,282)	159,457		17,728	820,338
	INTERCOMPANY ACCOUNTS:					
4	LPSCO - SDC					
4	SMLP - SDC					
4	SCM-SDC CASH ADVANCES 267	12,777,915				
4	GH-SDC INTERCO CAPITAL 265	1,432,265				
4	WWOS-SDC			48,503		
	INTEREST PAYABLE	5,371		97,397		
	S/T NOTES PAYABLE					
	$45 MILLION TERM LOAN					
	$55 MILLION RLC					
	GOLDEN HERITAGE (PEW)	398,595				
	TEXTRON LOAN - PVGC					
	DEF PROFIT & UNEARNED REVENUE		97,416			58,449
	PWCC INTERCO PAYABLE					
	APS LAND INTERCO PAYABLE					(0)
	CUSTOMER DEPOSITS	1,694,749				
	TOTAL CURRENT LIABILITIES	19,018,368	1,293,618	724,417	17,728	1,081,424
	LONG-TERM LIABILITIES					
	LONG-TERM NOTES PAYABLE					
	WWOS OWES SDC PH I LAND NOTE			1,304,153		
	WWOS RLC PAYOFF BY SDC			10,000,000		
	CORPORATE TERM NOTE					
	CORPORATE RLC					
	LPSCO OWES SDC					
	TEXTRON LOAN - PVGC					
5	OTHER ACCRUED LIABILITIES		224,212			230,145
5	DEFERRED TAXES					
5	LONG-TERM CUSTOMER DEPOSITS					
5	CONTRIB PROPERTY AIA					
	TOTAL L/T LIABILITIES	0	224,212	11,304,153	0	230,145
	TOTAL LIABILITIES	19,018,368	1,517,830	12,028,570	17,728	1,311,568
	MINORITY INTEREST					

	ACCOUNT DESCRIPTION	H HILLS	R VIEJO	C. CANYON	ELIMINATIONS REF	ELIMINATIONS DEBIT	ELIMINATIONS REF	ELIMINATIONS CREDIT
	LIABILITIES:							
	CURRENT LIABILITIES							
4	A/P & RETENTION	$ 1,200	$ 350,326	$ 5,197 J,K,Q		$ 315,272		$ --
4	ACCRUED LIABILITIES	29,837	207,991					
	INTERCOMPANY ACCOUNTS:							
4	LPSCO - SDC				H	21,391		
4	SMLP - SDC				J	27,761		0
4	SCM-SDC CASH ADVANCES 267				B	12,777,915		0
4	GH-SDC INTERCO CAPITAL 265				A	1,432,265		0
4	WWOS-SDC				Q	48,503		0
	INTEREST PAYABLE				P	97,398		
	S/T NOTES PAYABLE							
	$45 MILLION TERM LOAN							
	$55 MILLION RLC							
	GOLDEN HERITAGE (PEW)							0

	TEXTRON LOAN - PVGC						*	59,956
	DEF PROFIT & UNEARNED REVENUE				E	2,565,923		
	PWCC INTERCO PAYABLE							
	APS LAND INTERCO PAYABLE							
	CUSTOMER DEPOSITS							
	TOTAL CURRENT LIABILITIES	31,037	558,317	5,197	0	17,286,430	0	59,956
	LONG-TERM LIABILITIES							
	LONG-TERM NOTES PAYABLE							
	WWOS OWES SDC PH I LAND NOTE				P	1,304,153		
	WWOS RLC PAYOFF BY SDC				P	10,000,000		
	CORPORATE TERM NOTE							
	CORPORATE RLC							
	LPSCO OWES SDC				G	300,000		
	TEXTRON LOAN - PVGC				*	59,956		
5	OTHER ACCRUED LIABILITIES							
5	DEFERRED TAXES							
5	LONG-TERM CUSTOMER DEPOSITS							
5	CONTRIB PROPERTY AIA							
	TOTAL L/T LIABILITIES	0	0	0		11,664,109		0
	TOTAL LIABILITIES	31,037	558,317	5,197		28,950,539		59,956
	MINORITY INTEREST				I	7,985,114	I,R	13,747,038

	ACCOUNT DESCRIPTION	CONSOLIDATED
	LIABILITIES:	
	CURRENT LIABILITIES	
4	A/P & RETENTION	$ 5,090,181
4	ACCRUED LIABILITIES	3,756,908
	INTERCOMPANY ACCOUNTS:	
4	LPSCO - SDC	0
4	SMLP - SDC	0
4	SCM-SDC CASH ADVANCES 267	0
4	GH-SDC INTERCO CAPITAL 265	0
4	WWOS-SDC	0
	INTEREST PAYABLE	449,286
	S/T NOTES PAYABLE	
	$45 MILLION TERM LOAN	3,208,144
	$55 MILLION RLC	0
	GOLDEN HERITAGE (PEW)	398,595
	TEXTRON LOAN - PVGC	59,956
	DEF PROFIT & UNEARNED REVENUE	270,434
	PWCC INTERCO PAYABLE	358,870
	APS LAND INTERCO PAYABLE	(0)
	CUSTOMER DEPOSITS	1,694,749
	TOTAL CURRENT LIABILITIES	15,287,123
	LONG-TERM LIABILITIES	
	LONG-TERM NOTES PAYABLE	
	WWOS OWES SDC PH I LAND NOTE	0
	WWOS RLC PAYOFF BY SDC	0
	CORPORATE TERM NOTE	38,853,019
	CORPORATE RLC	38,138,836
	LPSCO OWES SDC	0
	TEXTRON LOAN - PVGC	3,428,898
5	OTHER ACCRUED LIABILITIES	4,905,519
5	DEFERRED TAXES	216,617
5	LONG-TERM CUSTOMER DEPOSITS	586,162
5	CONTRIB PROPERTY AIA	916,642
	TOTAL L/T LIABILITIES	87,045,693
	TOTAL LIABILITIES	102,332,816
	MINORITY INTEREST	5,761,924

ACCOUNT DESCRIPTION	SUNCOR CORPORATE	LPSCO	SASI	SMLP	PVGC
EQUITY:					
SDC COMMON STOCK	1,022,000				
SDC ADDITIONAL PAID IN CAPITAL	375,368,522				
SDC EARNED SURPLUS-BEGINNING	(116,158,648)				
SDC EARNED SURPLUS-CURRENT	44,719,992				
SUBSIDIARY EARNINGS-CURRENT		30,780	159,366	4,759,433	(127,903)
SUBSIDIARY EQUITY:					
LPSCO		11,895,460			
SASI			214,415		
SMLP #3500				2,436,916	
PVGC					6,359,255
HOMEBUILDING					
PALM VALLEY #5500					
WWOS #4400					
KABUTO JV #3000					
COMMERCIAL PROPERTIES #2000					
HIDDEN HILLS #3300					
RANCHO VIEJO #6600					
CORAL CANYON #3900					
TOTAL EQUITY	304,951,866	11,926,240	373,781	7,196,349	6,231,352
TOTAL LIABS AND EQUITY	$394,411,858	$ 15,275,727	$ 499,296	$ 7,397,716	$ 9,829,775

ACCOUNT DESCRIPTION	HOMES	PV	WWOS	KABUTO JV	COMM.
EQUITY:					
SDC COMMON STOCK					
SDC ADDITIONAL PAID IN CAPITAL					
SDC EARNED SURPLUS-BEGINNING					
SDC EARNED SURPLUS-CURRENT					
SUBSIDIARY EARNINGS-CURRENT	1,046,001	6,128,499	(90,343)	0	3,604,982
SUBSIDIARY EQUITY:					
LPSCO					
SASI					
SMLP #3500					
PVGC					
HOMEBUILDING	634,276				
PALM VALLEY #5500		161,092,534			
WWOS #4400			4,891,083		
KABUTO JV #3000				12,687,657	
COMMERCIAL PROPERTIES #2000					81,014,621
HIDDEN HILLS #3300					
RANCHO VIEJO #6600					
CORAL CANYON #3900					
TOTAL EQUITY	1,680,277	167,221,032	4,800,740	12,687,657	84,619,603
TOTAL LIABS AND EQUITY	$ 20,698,645	$ 168,738,862	$ 16,829,310	$ 12,705,385	$ 85,931,172

ACCOUNT DESCRIPTION	H HILLS	R VIEJO	C. CANYON	ELIMINATIONS REF	ELIMINATIONS DEBIT	ELIMINATIONS REF	ELIMINATIONS CREDIT
EQUITY:							
SDC COMMON STOCK							
SDC ADDITIONAL PAID IN CAPITAL							
SDC EARNED SURPLUS-BEGINNING							
SDC EARNED SURPLUS-CURRENT							
SUBSIDIARY EARNINGS-CURRENT	(1,502)	(61,761)		F,L,I,S,V	15,729,061	O,T,U,M	281,505
SUBSIDIARY EQUITY:							
LPSCO				F	11,895,460		
SASI				L	864,415	L	650,000
SMLP #3500				I	26,152,149	I	23,715,233
PVGC				M	6,359,255		0
HOMEBUILDING				D	634,276		0
PALM VALLEY #5500				V	161,092,534		
WWOS #4400				O	23,860,125	O	18,969,042
KABUTO JV #3000				R	12,687,657		
COMMERCIAL PROPERTIES #2000				S	81,014,621		0
HIDDEN HILLS #3300	1,172,147			T	1,173,714	T	1,567
RANCHO VIEJO #6600		8,735,943		U	8,759,885	U	23,942
CORAL CANYON #3900			481,241	W	481,241		
TOTAL EQUITY	1,170,645	8,674,182	481,241		350,704,393		43,641,289
TOTAL LIABS AND EQUITY	$ 1,201,682	$ 9,232,499	$ 486,439		$387,640,045		$ 57,448,282

ACCOUNT DESCRIPTION	CONSOLIDATED
EQUITY:	
SDC COMMON STOCK	1,022,000
SDC ADDITIONAL PAID IN CAPITAL	375,368,522
SDC EARNED SURPLUS-BEGINNING	(116,158,648)
SDC EARNED SURPLUS-CURRENT	44,719,992
SUBSIDIARY EARNINGS-CURRENT	(3)
SUBSIDIARY EQUITY:	
LPSCO	0
SASI	0
SMLP #3500	0
PVGC	0
HOMEBUILDING	0
PALM VALLEY #5500	0
WWOS #4400	0
KABUTO JV #3000	0
COMMERCIAL PROPERTIES #2000	0
HIDDEN HILLS #3300	(0)
RANCHO VIEJO #6600	0
CORAL CANYON #3900	0
TOTAL EQUITY	304,951,863
TOTAL LIABS AND EQUITY	$ 413,046,603

SUNCOR DEVELOPMENT COMPANY
CONSOLIDATING BALANCE SHEET
DECEMBER 1998 CONSOLIDATING AND ELIMINATING ENTRIES

	DEBIT	CREDIT
A. SCM INTERCO A/P TO SDC	$ 4,981,309	
SDC A/R FROM SCM		$ 4,981,309
GH INTERCO CAPITAL FROM SDC - ACQUISITION	$ 1,432,265	
GH INTERCO A/P TO SDC		$ 664,537
SDC A/R FROM GH		$ 767,728
B. HOMEBUILDING CASH ADVANCES FROM SDC	$12,777,915	
SDC CASH ADVANCES TO HOMEBUILDING		$12,777,915
C. SCM INTERCO CAPPED INTEREST	$ 2,592,637	
SDC INTERCO INTEREST A/R FROM SCM		$ 2,592,637
ELIMINATE INTERCO RECEIVABLES/PAYABLES BETWEEN HOMEBUILDING AND SDC		
D. HOMEBUILDING ACCUMULATED EARNINGS	$ 634,276	
SDC INVESTMENT IN GH		$ 1,154,335
SDC INVESTMENT IN SCM		$ 525,943
HOMEBUILDING CURRENT YEAR EARNINGS	$ 1,046,001	
ELIMINATE SDC INVESTMENT IN GOLDEN HERITAGE & SCM		
E. DEFERRED INTERCO PROFIT	$ 2,565,923	
HOME INVENTORY		$ 2,565,923
ELIMINATE DEFERRED PROFIT ON INTERCO LOT SALES TO HOMEBUILDING		
F. LPSCO COMMON STOCK	$ 78,200	
LPSCO PAID IN CAPITAL	$11,151,953	
LPSCO EARNINGS - PRIOR	$ 665,307	
LPSCO EARNINGS - CURRENT YEAR	$ 30,780	
SDC INVESTMENT IN LPSCO - CONTRIB CAPITAL		$11,230,153
SDC INVESTMENT IN LPSCO - EARNINGS		$ 695,515
ELIMINATE SDC INVESTMENT IN LPSCO		
G. LPSCO LONG-TERM NOTES PAYABLE	$ 300,000	
SDC LONG-TERM NOTES RECEIVABLE		$ 300,000
ELIMINATE LPSCO INTERCOMPANY NOTE WITH SDC		
H. LPSCO ACCOUNTS PAYABLE	$ 21,391	
SDC ACCOUNTS RECEIVABLE		$ 21,391
ELIMINATE LPSCO INTERCOMPANY A/R WITH SDC		

SUNCOR DEVELOPMENT COMPANY
CONSOLIDATING BALANCE SHEET
DECEMBER 1998 CONSOLIDATING AND ELIMINATING ENTRIES

	DEBIT	CREDIT
I. SMLP CONTRIBUTED CAPITAL - MINORITY INT		$ 7,985,114
SMLP CONTRIBUTED CAPITAL - SDC GP	$ 490,147	
SMLP DISTRIBUTED CAPITAL - SDC GP		$ 9,878,612
SMLP CONTRIBUTED CAPITAL - SDC LP	$ 2,100,000	
SMLP DISTRIBUTED CAPITAL - SDC LP		$ 5,851,507
SMLP EARNINGS - PRIOR	$23,562,002	
SMLP EARNINGS - CURRENT YEAR	$ 4,759,433	
MINORITY INTEREST CONTRIBUTED CAPITAL	$ 7,985,114	
MINORITY INTEREST - PRIOR (35%)		$ 8,246,701
MINORITY INTEREST - CURRENT YEAR (35%)		$ 1,665,802
SDC INVESTMENT IN SMLP - LP		$ 2,100,000
SDC DISTRIBUTIONS FROM SMLP - LP	$ 5,851,507	
SDC INVESTMENT IN SMLP - GP		$ 490,147
SDC DISTRIBUTIONS FROM SMLP - GP	$ 9,878,612	
SDC INVESTMENT IN SMLP - EARNINGS		$18,408,933
ELIMINATE SDC INVESTMENT IN SMLP #3500		
J. SMLP ACCOUNTS PAYABLE	$ 27,761	
SDC ACCOUNTS RECEIVABLE		$ 27,761
GH ACCOUNTS PAYABLE	$ 310,000	
SMLP ACCOUNTS RECEIVABLE		$ 310,000
ELIMINATE SMLP INTERCOMPANY A/R WITH SDC AND HOMEBUILDING (PREMIUMS)		
K. SASI ACCOUNTS PAYABLE	$ 0	$ 0
SDC ACCOUNTS RECEIVABLE	$ 0	$ 0
ELIMINATE SASI INTERCOMPANY A/R WITH SDC		
L. SASI CONTRIBUTED CAPITAL	$ 489,023	
SASI CAPITAL DISTRIBUTIONS		$ 650,000
SASI EARNINGS - PRIOR	$ 375,392	
SASI EARNINGS - CURRENT YEAR	$ 159,366	
PV INVESTMENT IN SASI - CONTRIB CAPITAL		$ 489,023
PV INVESTMENT IN SASI - DISTRIBUTIONS	$ 650,000	
PV INVESTMENT IN SASI - EARNINGS		$ 534,758
ELIMINATE PALM VALLEY INVESTMENT IN SASI		
M. PVGC CONTRIBUTED CAPITAL	$ 6,158,173	
PVGC EARNINGS - PRIOR	$ 201,082	
PVGC EARNINGS - CURRENT YEAR		$ 127,903
SDC INVESTMENT IN PVGC - EARNINGS		$ 73,179
SDC INVESTMENT IN PVGC - CONTRIB CAPITAL		$ 6,158,173
ELIMINATE SDC INVESTMENT IN PALM VALLEY GOLF		
N. SDC CONTRIB. CAPITAL TO PVGC	$ 4,060,675	
PVGC ACCOUNTS RECEIVABLE		$ 4,060,675

SUNCOR DEVELOPMENT COMPANY
CONSOLIDATING BALANCE SHEET
DECEMBER 1998 CONSOLIDATING AND ELIMINATING ENTRIES

	DEBIT	CREDIT
ELIMINATE PALM VALLEY GOLF INTERCOMPANY A/R WITH SDC		
O. WWOS CONTRIBUTED CAPITAL - PHASE 1	$ 9,500,000	
WWOS CONTRIBUTED CAPITAL - PHASE 2	$13,522,531	
WWOS CONTRIBUTED WORKING CAPITAL	$ 837,594	
WWOS EARNINGS - PRIOR		$ 1,933,052
WWOS EARNINGS - CURRENT YEAR		$ 90,340
WWOS CAPITAL DISTRIBUTIONS - PHASE 1		$ 9,500,000
WWOS CAPITAL DISTRIBUTIONS - PHASE 2		$ 4,967,126
WWOS PREFERRED RETURN - PHASE 1		$ 287,568
WWOS PREFERRED RETURN - PHASE 2		$ 2,281,296
SDC INVESTMENT IN WWOS - PHASE 1		$ 9,500,000
SDC INVESTMENT IN WWOS - PHASE 2		$13,408,870
SDC INVESTMENT IN WWOS -CONTRIBUTED CAPITAL		$ 431,255
SDC INVESTMENT IN WWOS - EARNINGS	$ 2,023,392	
SDC DISTRIBUTIONS FROM WWOS - PHASE 1	$ 9,500,000	
SDC DISTRIBUTIONS FROM WWOS - PHASE 2	$ 4,967,126	
SDC PREFERRED RETURN - PHASE 1	$ 287,568	
SDC PREFERRED RETURN - PHASE 2	$ 1,761,296	
ELIMINATE SDC COMMERCIAL INVESTMENT IN WIGWAM OUTLET STORES #4400		
P. WWOS INTEREST PAYABLE - PHASE 1 LAND	$ 29,585	
WWOS INTEREST PAYABLE - RLC	$ 67,813	
SDC INTEREST RECEIVABLE - PHASE 1 LAND		$ 29,585
SDC INTEREST RECEIVABLE - RLC		$ 67,813
WWOS NOTES PAYABLE - PHASE 1 LAND	$ 1,304,153	
SDC NOTES RECEIVABLE - PHASE 1 LAND		$ 1,304,153
WWOS NOTES PAYABLE - RLC	$10,000,000	
SDC NOTES RECEIVABLE - RLC		$10,000,000
ELIMINATE WWOS INTERCOMPANY NOTES AND INTEREST WITH SDC		
Q. WWOS ACCOUNTS PAYABLE		$ 48,503
SDC ACCOUNTS RECEIVABLE	$ 48,503	
WWOS MANAGEMENT FEE PAYABLE	$ 5,272	
SDC COMMERCIAL A/R		$ 5,272
ELIMINATE WWOS INTERCOMPANY A/R WITH SDC		
R. KABUTO CONTRIBUTED CAPITAL - SDC	$ 8,853,122	
KABUTO CONTRIBUTED CAPITAL - KABUTO	$ 3,834,535	
MINORITY INTEREST		$ 3,834,535
SDC INVESTMENT IN KABUTO - CONTR CAPITAL		$ 5,981,619
BALANCING PLUG		$ 2,871,502
ELIMINATE SDC INVESTMENT IN KABUTO JV #3000		
S. COMMERCIAL OPS CONTRIBUTED CAPITAL	$80,522,808	
COMMERCIAL EARNINGS - PRIOR	$ 491,813	
COMMERCIAL EARNINGS - CURRENT YEAR	$ 3,604,982	
SDC INVEST IN GEN COMMERCIAL OPS - EARNINGS		$ 1,636,480
SDC INVEST IN GEN COMMERCIAL OPS - CONT CAPITAL		$77,619,340
SDC INVESTMENT IN OUTER LIMITS - PURCHASE		$ 1,822,515

SUNCOR DEVELOPMENT COMPANY
CONSOLIDATING BALANCE SHEET
DECEMBER 1998 CONSOLIDATING AND ELIMINATING ENTRIES

	DEBIT	CREDIT
SDC INVESTMENT IN FIDDLE (SCOTTS) - CONT CAPITAL	$ 2,012,593	
SDC INVESTMENT IN FIDDLE (SCOTTS) - EARNINGS	$ 413,484	
SDC INVESTMENT IN FUNTASTICKS - CONT CAPITAL		$ 2,043,745
SDC INVESTMENT IN FUNTASTICKS - EARNINGS		$ 290,658
SDC INVESTMENT IN FIDDLE (TEMPE) - CONT CAPITAL		$ 1,049,800
SDC INVESTMENT IN FIDDLE (TEMPE) - EARNINGS		$ 573,717
SDC INVESTMENT IN PV MARKETPLACE - EARNINGS		$ 1,406,129
SDC INVESTMENT IN PV PAVILIONS - EARNINGS		$ 899,849
SDC INVESTMENT IN PV CROSSING - EARNINGS		$ 311,587
SDC INVESTMENT IN METROCENTER - EARNINGS		$ 253,727
SDC INVESTMENT IN REST PLACE - EARNINGS	$ 65,725	
SDC INVESTMENT IN LITCHFIELD OTHER - EARNINGS		$ 73,203
SDC INVESTMENT IN AUTOPLEX - EARNINGS	$ 574,137	
SDC INVESTMENT IN TALAVI - EARNINGS	$ 139,299	
SDC INVESTMENT IN WWOS - EARNINGS	$ 11,397	
SDC INVESTMENT IN LP PROF. PLAZA - EARNINGS	$ 18,428	
SDC INVESTMENT IN APS PROPERTIES - EARNINGS	$ 126,084	
ELIMINATE SDC INVESTMENT IN COMMERCIAL OPERATIONS #2000		
T. HIDDEN HILLS CONTRIBUTED CAPITAL	$ 1,173,714	
HIDDEN HILLS EARNINGS - PRIOR		$ 1,567
HIDDEN HILLS EARNINGS - CURRENT YEAR		$ 1,503
SDC INVESTMENT IN HIDDEN HILLS - EARNINGS	$ 3,070	
SDC INVESTMENT IN HIDDEN HILLS - CONT CAPITAL		$ 1,173,907
ELIMINATE SDC INVESTMENT IN HIDDEN HILLS JV #3300		
U. SDC INVESTMENT IN RANCHO VIEJO - EARNINGS	$ 85,702	
SDC INVESTMENT IN RANCHO VIEJO - CAPITAL		$ 8,759,885
RANCHO VIEJO CONTRIBUTED CAPITAL	$ 8,759,885	
RANCHO VIEJO EARNINGS - PRIOR		$ 23,942
RANCHO VIEJO EARNINGS - CURRENT YEAR		$ 61,760
ELIMINATE SDC INVESTMENT IN RANCHO VIEJO JV #6600		
V. PV CONTRIBUTED CAPITAL	$157,595,695	
PV EARNINGS - PRIOR	$ 3,496,839	
PV EARNINGS - CURRENT YEAR	$ 6,128,499	
SDC INVESTMENT IN PALM VALLEY - EARNINGS		$ 9,625,558
SDC INVESTMENT IN PALM VALLEY - DEVELOP		$157,595,695
ELIMINATE SDC INVESTMENT IN PALM VALLEY #5500		
W. CORAL CANYON CONTRIBUTED CAPITAL	$ 481,241	
SDC INVESTMENT IN CORAL CANYON		$ 481,241
ELIMINATE SDC INVESTMENT IN CORAL CANYON #3900		

SunCor Development Company
Consolidating Income Statement (Unaudited)
For the Year Ending December 31, 1998

Account Description	SunCor	LPSCo	Scts Mtn	PVGC	GHH
Revenues					
Home Sales	$ 0	$ 0	$ 0	$ 0	$50,228,047
Land Sales	50,859,043	0	10,017,886	0	0
Commercial Properties	5,143,994	0	0	2,113,400	0
Utility Sales	0	2,095,302	0	0	0
Management Fees	1,180,276	0	0	0	0
Total Operating Revenues	57,183,313	2,095,302	10,017,886	2,113,400	50,228,047
Operating Expenses					
Cost of Homes Sold	(2,439,803)	0	0	0	43,395,872
Cost of Land Sold	40,202,747	0	5,042,867	0	0
Commercial Properties	5,552,147	0	0	202,461	0
Utility Expense	0	1,639,443	0	0	0
Land Project Costs	1,901,734	0	123,984	0	0
General & Administrative	10,213,245	0	146,953	1,493,611	5,402,670
Depreciation & Amortization	960,152	385,008	47	192,911	510,016
Total Operating Expenses	56,390,222	2,024,451	5,313,850	1,888,983	49,308,558
Net Operating Income/(Loss)	793,091	70,851	4,704,035	224,417	919,490
Other Income and Gains					
Equity in Joint Ventures	4,585,909	0	0	0	0
Interest Income	737,547	7,799	55,783	0	0
Other	0	0	0	0	180,203
Total Other Income and Gains	5,323,456	7,799	55,783	0	180,203
Interest Expense, Net					
Interest Expense	5,249,779	47,870	385	352,320	53,691
Less: Capitalized Interest	(2,333,492)	0	0	0	0
Total Interest Expense, Net	2,916,287	47,870	385	352,320	53,691
Minority Interest	1,234,975	0	0	0	0
Income before Taxes	1,965,286	30,780	4,759,433	(127,903)	1,046,001
Income Taxes	(37,200,000)	0	0	0	0
NET INCOME/(LOSS)	$39,165,286	$ 30,780	$ 4,759,433	($127,903)	$ 1,046,001

Account Description	WWOS	Hidden Hills	Rancho Viejo	Consolidated Income
Revenues				
Home Sales	$ 0	$ 0	$ 0	$ 50,228,047
Land Sales	0	0	634,992	61,511,921
Commercial Properties	3,095,236	0	0	10,352,630
Utility Sales	0	0	0	2,095,302
Management Fees	0	0	0	1,180,276
Total Operating Revenues	3,095,236	0	634,992	125,368,176
Operating Expenses				
Cost of Homes Sold	0	0	0	40,956,069
Cost of Land Sold	0	0	478,121	45,723,735
Commercial Properties	1,401,090	0	0	7,155,698
Utility Expense	0	0	0	1,639,443
Land Project Costs	0	947	97,682	2,124,347
General & Administrative	0	556	125,340	17,382,374
Depreciation & Amortization	845,355	0	2,306	2,895,795
Total Operating Expenses	2,246,445	1,503	703,449	117,877,461
Net Operating Income/(Loss)	848,791	(1,503)	(68,457)	7,490,715
Other Income and Gains				
Equity in Joint Ventures	0	0	0	4,585,909
Interest Income	4,536	0	6,698	812,363
Other	0	0	0	180,203
Total Other Income and Gains	4,536	0	6,698	5,578,475
Interest Expense, Net				
Interest Expense	943,670	0	0	6,647,715
Less: Capitalized Interest	0	0	0	(2,333,492)
Total Interest Expense, Net	943,670	0	0	4,314,223
Minority Interest	0	0	0	1,234,975
Income before Taxes	(90,343)	(1,503)	(61,760)	7,519,992
Income Taxes	0	0	0	(37,200,000)
NET INCOME/(LOSS)	($90,343)	($1,503)	($61,760)	$ 44,719,992

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Company: PINNACLE WEST CAPITAL CORP
Form Type: U-3A-2 SEC File #: 069-00306
Description: FORM U-3A-2
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Adopted November 9, 1939 File No. 69-306

SECURITIES AND EXCHANGE COMMISSION
Washington, D.C.

FORM U-3A-2

Statement by Holding Company
Claiming Exemption under Rule U-2
from the Provisions of the
Public Utility Holding Company Act of 1935

To Be Filed Annually Prior to March 1

Pinnacle West Capital Corporation

(Name of Company)

hereby files with the Securities and Exchange Commission, pursuant to Rule 2, its statement claiming exemption as a holding company from the provisions of the Public Utility Holding Company Act of 1935, and submits the following information:

1. Name, state of organization, location and nature of business of Claimant and every subsidiary thereof, other than any exempt wholesale generator (EWG) or foreign utility company in which Claimant directly or indirectly holds an interest.

Pinnacle West Capital Corporation ("Claimant"), having been incorporated on February 20, 1985 under the laws of the State of Arizona, and having its principal executive offices at 400 East Van Buren, Suite 700, Phoenix, Arizona 85004, was organized principally to acquire and hold securities of other corporations for investment purposes. Claimant currently holds stock in the following subsidiaries:

a. Arizona Public Service Company ("APS" or the "Company"), is engaged principally in serving electricity in the State of Arizona. Incorporated in 1920 under the laws of the State of Arizona and having its principal executive offices at 400 North Fifth Street, Phoenix, Arizona 85004, APS became a subsidiary of the Claimant pursuant to a corporate restructuring plan approved by the Company's shareholders on April 18, 1985.

(1) AXIOM Power Solutions, Inc. ("AXIOM") -- an Arizona corporation having been incorporated on October 29, 1996 and having its principal executive offices at 400 E. Van Buren, Phoenix, Arizona 85004, was organized primarily to sell security and energy management products and services. AXIOM is a wholly-owned subsidiary of APS.

(2) Bixco, Inc. ("Bixco") -- an Arizona corporation having been incorporated on June 4, 1971 and having its principal executive offices at 400 North Fifth Street, Phoenix, Arizona 85004, was organized primarily to conduct exploration activities for energy resources and other valuable minerals. Subsequent to the sale of its oil and natural gas properties in 1981, Bixco has been inactive. Bixco is a wholly-owned subsidiary of APS.

b. SunCor Development Company ("SunCor") -- an Arizona corporation having been incorporated on June 30, 1965 and having its principal executive offices at 3838 North Central Avenue, Suite 1500, Phoenix, Arizona 85012, is a wholly-owned subsidiary of Claimant engaged primarily in the owning, holding and development of real property.

(1) SunCor Resort & Golf Management, Inc. ("Resort & Golf Management") (previously named "SunCor Resort Management, Inc." and "SunCor Farms, Inc.") -- an Arizona corporation having been incorporated on December 31, 1986 and having its principal executive offices at 3838 North Central Avenue, Suite 1500, Phoenix, Arizona 85012 operates and manages hotel, golf, food and beverage for the Wigwam Resort and Country Club, Sedona Golf Resort, SunRidge Canyon Golf Club, Real del Mar Golf Club, and Palm Valley Golf Club. Resort & Golf Management is a wholly-owned subsidiary of SunCor.

(2) Litchfield Park Service Company ("LPSCO") -- an Arizona corporation having been incorporated on September 21, 1954 and having its principal executive offices at 501 East Plaza Circle, Suite B, Litchfield Park, Arizona 85340, is a regulated public utility engaged in providing water and sewer services to commercial and residential customers. LPSCO became a wholly-owned subsidiary of SunCor on December 31, 1986.

(3) Golden Heritage Homes, Inc.. ("Golden Heritage Homes") -- (previously named "SunCor Homes, Inc.", LGR, Inc. and "WGP Realty, Inc.") an Arizona corporation having been incorporated on May 14, 1986 and having its principal executive offices at 3838 North Central Avenue, Suite 1500, Phoenix, Arizona 85012, was organized to provide brokerage and realty services in the sale of commercial and residential real property. Golden Heritage Homes is a wholly-owned subsidiary of SunCor.

(i) Golden Heritage Construction, Inc. ("GH Construction") -- an Arizona corporation having been incorporated on December 30, 1993 and having its principal executive offices at 7975 North Hayden Rd. Suite D-280, Scottsdale, Arizona 85258, was organized to serve as a general residential contractor. GH Construction became a wholly-owned subsidiary of Golden Heritage Homes, Inc. on January 1, 1996.

(4) SCM, Inc. ("SCM") -- an Arizona corporation having been incorporated on May 14, 1991 and having its principal executive offices at 3838 North Central Avenue, Suite 1500, Phoenix, Arizona 85012, was organized to

participate in real estate joint ventures and other real estate related activities. SCM is a wholly-owned subsidiary of SunCor.

(5) Golf de Mexico, S.A. DE C.V. ("Golf de Mexico") -- a Mexican variable capital corporation having been incorporated on February 8, 1992 in Tijuana, Baja California, Mexico, and having its principal executive offices at 3838 North Central Avenue, Suite 1500, Phoenix, Arizona 85012, was organized to operate and manage the Real del Mar Golf Course in Mexico. Golf de Mexico has been inactive.

(6) SunCor Realty & Management Company ("SunCor Realty") -- (previously named Russell Ranch Development Company) an Arizona corporation having been incorporated on April 1, 1994 and having its principal executive offices at 3838 North Central Avenue, Suite 1500, Phoenix, Arizona 85012 was organized to participate in real estate joint ventures and other real estate related activities. SunCor Realty is a wholly-owned subsidiary of SunCor.

(7) Palm Valley Golf Club, Inc. ("Palm Valley Golf") -- an Arizona corporation having been incorporated on January 23, 1996 and having its principal executive offices at 3838 North Central Avenue, Suite 1500, Phoenix, Arizona 85012 was organized to hold title to the Palm Valley Golf Course. Palm Valley Golf is a wholly-owned subsidiary of SunCor.

(8) Rancho Viejo de Santa Fe, Inc. ("Rancho Viejo") -- a New Mexico corporation having been incorporated on March 18, 1996 and having its principal executive offices at 3838 North Central Avenue, Suite 1500, Phoenix, Arizona 85012 was organized to engage in real estate development in New Mexicq. Rancho Viego is a wholly-owned subsidiary of SunCor.

(9) Ranchland Utility Company ("Ranchland") - - A New Mexico Corporation having been incorporated on September 5, 1997 and having its principal executive offices at 1590-B Pacheco Street, Santa Fe, New Mexico 87505 is a waste water utility. Ranchland is a wholly-owned subsidiary of Rancho Viejo.

c. El Dorado Investment Company -- an Arizona corporation having been incorporated on July 27, 1983 and having its principal executive offices at 400 East Van Buren, Suite 800, Phoenix, Arizona 85004, is a wholly-owned subsidiary of Claimant engaged primarily in the acquisition and holding of stocks and securities of other companies for investment purposes.

2. A brief description of the properties of Claimant and each of its subsidiary public utility companies used for the generation, transmission and distribution of electric energy for sale, or for the production, transmission and distribution of natural or manufactured gas, indicating the location of principal generating plants, transmission lines, producing fields, gas manufacturing plants and electric and gas distribution facilities, including all such properties which are outside the state in which Claimant and its subsidiaries are organized and all transmission or pipelines which deliver or receive electric energy or gas at the borders of such state.

Neither the Claimant nor any of its subsidiaries own property used for the production, transmission and distribution of natural or manufactured gas. APS, a "public utility company" as that term is defined in the Public Utility Holding Company Act of 1935, is the only one of Claimant's subsidiaries that owns property used for the generation, transmission and distribution of electric energy for sale.

Exhibit D attached hereto shows the location of APS' major generating plants (including those owned jointly with others), principal transmission lines (including those operated for others) and interconnections of transmission lines with out-of-state utilities at state lines. All of such facilities, except the Four Corners Generating Station ("Four Corners"), and all of APS' distribution facilities, are located within the State of Arizona. Four Corners is a mine-mouth power plant, located in the northwest corner of New Mexico, near the city of Farmington, approximately 40 miles east of the Arizona-New Mexico border.

APS' present generating facilities have an accredited capacity aggregating 4,006,109 kilowatts, comprised as follows:

	Capacity
Coal:	
Units 1, 2 and 3 at Four Corners, aggregating	560,000 kw
15% owned Units 4 and 5 at Four Corners, representing	222,000
Units 1, 2, and 3 at the Cholla Plant, aggregating	615,000
14% owned Units 1, 2 and 3 at the Navajo Plant, representing	315,000
	1,712,000 kw
Gas or Oil:	
Two steam units at Ocotillo, two steam units at Saguaro aggregating	435,000 kw(1)
Eleven combustion turbine units, aggregating	493,000
Three combined cycle units, aggregating	255,000
	1,183,000 kw
Nuclear:	
29.1% owned or leased Units 1, 2 and 3 at Palo Verde, representing	1,105,509 kw
Other (Hydro)	5,600 kw

(1)West Phoenix steam units (96,300 kw) are currently mothballed.

APS' transmission facilities consist of approximately 4,544 pole miles of overhead lines and approximately 9,587 miles of underground lines, all of which are located within the State of Arizona. APS' distribution facilities consist of approximately 11,197 pole miles of overhead lines and approximately 9,587 miles of underground lines, all of which are located within the State of Arizona.

3. The following information for the last calendar year with respect to Claimant and each of its subsidiary public utility companies:

a. Number of kwh of electric energy sold at retail or wholesale.

Claimant	APS
None	29,050,500,000 kwh of electric energy sold at wholesale or retail

b. Number of kwh of electric energy distributed at retail outside the state in which each such company is organized.

Claimant	APS
None	59,405,000 kwh of electric energy distributed at retail outside Arizona

c. Number of kwh of electric energy sold at wholesale outside the state in which each such company is organized, or at the state line.

Claimant	APS
None	926,900 kwh of electric energy sold at wholesale outside Arizona or at state line

d. Number of kwh of electric energy purchased outside the state in which each such company is organized or at the state line.

Claimant	APS
None	0 kwh of electric energy purchased outside Arizona or at state line

4. The following information for the reporting period with respect to Claimant and each interest it holds directly or indirectly in an EWG or a foreign utility company, stating monetary amounts in United States dollars:

The Claimant holds no interest, direct or indirect, in an EWG or a foreign utility company.

a. Name, location, business address and description of the facilities used by the EWG or foreign utility company for the generation, transmission and distribution of electric energy for sale or for the distribution at retail of natural or manufactured gas.

Not applicable.

b. Name of each system company that holds an interest in such EWG or foreign utility company; and description of the interest held.

Not applicable.

c. Type and amount of capital invested, directly or indirectly, by the holding company claiming exemption; any direct or indirect guarantee of the security of the EWG or foreign utility company by the holding company claiming exemption; and any debt or other financial obligation for which there is recourse, directly or indirectly, to the holding company claiming exemption or another system company, other than the EWG or foreign utility company.

Not applicable.

d. Capitalization and earnings of the EWG or foreign utility company during the reporting period.

Not applicable.

e. Identify any service, sales or construction contract(s) between the EWG or foreign utility company and a system company, and describe the services to be rendered or goods sold and fees or revenues under such agreement(s).

Not applicable.

EXHIBIT A

A consolidating statement of income and surplus of the Claimant and its subsidiary companies for the last calendar year, together with a consolidating balance sheet of Claimant and its subsidiary companies as of the close of such calendar year.

Exhibit A hereto includes consolidating statements of income and consolidating balance sheets for the Claimant and the following of its subsidiaries: Arizona Public Service Company, SunCor Development Company and El Dorado Investment Company. Subsidiaries have been consolidated for financial reporting purposes in accordance with Statement of Financial Accounting Standards No. 94, Consolidation of All Majority-Owned Subsidiaries. Also included are consolidating statements of income and consolidating balance sheets for SunCor Development Company and its subsidiaries.

EXHIBIT B FINANCIAL DATA STATEMENT

If, at the time a report on this form is filed, the registrant is required to submit this report and any amendments thereto electronically via EDGAR, the registrant shall furnish a Financial Data Schedule. The Schedule shall set forth the financial and other data specified below that are applicable to the registrant on a consolidated basis.

1. Total Assets.

2. Total Operating Revenues.

3. Net Income.

See Exhibit B hereto.

EXHIBIT B Financial Data Schedule

The Claimant submits the following consolidated financial information:

1. Total Assets: $6,850,417,000

2. Total Operating Revenues: $1,995,026,000

3. Net Income: $235,856,000

EXHIBIT C

An organizational chart showing the relationship of each EWG or foreign utility company to associate companies in the holding-company system.

Not applicable.

EXHIBIT D

Exhibit D is a map of the state of Arizona showing the following:

APS Service Area;
Major APS Power Plants, including joint ownership;
Principal APS Transmission Lines; and
Transmission Lines Operated for Others.

The above-named Claimant has caused this statement to be duly executed on its behalf by its authorized officer on this 27th day of February, 1998.

Pinnacle West Capital Corporation

(Name of Claimant)

By /s/ Michael S. Ash

Michael S. Ash
Corporate Counsel

[CORPORATE SEAL]

Attest:

/s/Suzanne Debes

Suzanne Debes
Associate Secretary

Name, title and address of officer to whom notices and correspondence concerning this statement should be addressed:

Michael S. Ash	Corporate Counsel	(Name)	(Title)
400 East Van Buren, Suite 700, Phoenix, Arizona 85004		(Address)	

PINNACLE WEST CAPITAL CORPORATION
CONSOLIDATING BALANCE SHEET
31-Dec-97
(THOUSANDS OF DOLLARS)

	PWCC	APS	SUNCOR	ELDO
A S S E T S				
CURRENT ASSETS				
Cash and cash equivalents	$ 7,322	$ 12,552	$ 5,108	$ 2,502
Customer and other receivables - net	1,023	170,997	4,507	10,072
Accrued utility revenue		58,559		
Materials and supplies		70,634		
Fossil fuel		9,621		
Deferred income taxes	53,601	3,496		790
Other current assets	52	24,529	16,955	--
Total current assets	61,998	350,388	26,570	13,364
INVESTMENTS AND OTHER ASSETS				
Real estate investments, net			365,799	
Other assets	2,201,006	164,906	6,721	21,152
Total investments and other	2,201,006	164,906	372,520	21,152
UTILITY PLANT				
Electric plant in service and held for future use		7,009,059		
Less accumulated depreciation and amortization		2,620,607		
Total		4,388,452		
Construction work in progress		237,492		
Nuclear Fuel		51,624		
Net Utility Plant		4,677,568		
DEFERRED DEBITS				
Regulatory asset for income taxes	--	458,369		
Rate synchronization deferral		358,871		
Other deferred debits	9,288	321,040	4,465	--
Total deferred debits	9,288	1,138,280	4,465	--
TOTAL ASSETS	$2,272,292	$6,331,142	$ 403,555	$ 34,516

	ELIMINATIONS AND ADJUSTING ENTRIES DEBIT	CREDIT	TOTAL
A S S E T S			
CURRENT ASSETS			
Cash and cash equivalents			$ 27,484
Customer and other receivables - net		3,092(b,h)	183,507
Accrued utility revenue			58,559
Materials and supplies			70,634
Fossil fuel			9,621
Deferred income taxes			57,887
Other current assets		128(c)	41,408
Total current assets		3,220	449,100
INVESTMENTS AND OTHER ASSETS			
Real estate investments, net	6,892(e)	6,770(d)	365,921
Other assets	2,069(h)	2,180,827(a,e)	215,027
Total investments and other	8,961	2,187,597	580,948
UTILITY PLANT			
Electric plant in service and held for future use			7,009,059
Less accumulated depreciation and amortization			2,620,607
Total			4,388,452
Construction work in progress			237,492
Nuclear Fuel			51,624
Net Utility Plant			4,677,568
DEFERRED DEBITS			
Regulatory asset for income taxes			458,369
Rate synchronization deferral			358,871
Other deferred debits		9,232(f)	325,561
Total deferred debits		9,232	1,142,801
TOTAL ASSETS	$ 8,961	$2,200,049	$6,850,417

PINNACLE WEST CAPITAL CORPORATION
CONSOLIDATING BALANCE SHEET
31-Dec-97
(THOUSANDS OF DOLLARS)

LIABILITIES AND EQUITY	PWCC	APS	SUNCOR	ELDO
CURRENT LIABILITIES				
Accounts payable	$ 2,089	$ 107,423	$ 7,786	$ 131
Accrued taxes	--	85,886	--	
Accrued interest	829	31,660	485	--
Commerical paper, net	--	130,750		
Current maturities of long-term debt	--	104,068	4,627	
Customer Deposits		29,116	1,556	
Other current liabilities	(420)	19,588	511	6
Total current liabilities	2,498	508,491	14,965	137
LONG-TERM DEBT LESS CURRENT MATURITIES	205,000	1,953,162	86,086	--
DEFERRED CREDITS AND OTHER				
Deferred income taxes	17,008	1,345,177		
Deferred investment tax credit		60,093		
Unamortized gain-sale of utility plant		82,363		
Other deferred credits	20,350	361,371	5,502	
Total deferred credits	37,358	1,849,004	5,502	--
COMMITMENTS AND CONTINGENCIES (NOTE)				
MINORITY INTERESTS:				
Non-Redeemable preferred stock of APS		142,051		
Redeemable preferred stock of APS		29,110		
Scottsdale Mountain of SunCor			6,770	
COMMON STOCK EQUITY:				
Common stock	2,026,872	1,320,526	406,391	50,046
Retained earnings	564	528,798	(116,159)	(15,667)
Total	2,027,436	1,849,324	290,232	34,379
TOTAL LIABILITIES AND EQUITY	$ 2,272,292	$ 6,331,142	$ 403,555	$ 34,516

LIABILITIES AND EQUITY	*ELIMINATIONS AND ADJUSTING ENTRIES* DEBIT	CREDIT	TOTAL
CURRENT LIABILITIES			
Accounts payable			$ 117,429
Accrued taxes	1,276(g)		84,610
Accrued interest			32,974
Commerical paper, net			130,750
Current maturities of long-term debt			108,695
Customer Deposits			30,672
Other current liabilities	1,151(b,c)		18,534
Total current liabilities	2,427	--	523,664
LONG-TERM DEBT LESS CURRENT MATURITIES	--	--	2,244,248
DEFERRED CREDITS AND OTHER			
Deferred income taxes		1,276(g)	1,363,461
Deferred investment tax credit	9,232(f)		50,861
Unamortized gain-sale of utility plant			82,363
Other deferred credits			387,223
Total deferred credits	9,232	1,276	1,883,908
COMMITMENTS AND CONTINGENCIES (NOTE)			
MINORITY INTERESTS:			
Non-Redeemable preferred stock of APS			142,051
Redeemable preferred stock of APS			29,110
Scottsdale Mountain of SunCor	6,770(d)		--
COMMON STOCK EQUITY:			
Common stock	2,250,064(a)		1,553,771
Retained earnings		76,129(a)	473,665
Total	2,250,064	76,129	2,027,436
TOTAL LIABILITIES AND EQUITY	$2,268,493	$ 77,405	$6,850,417

PINNACLE WEST CAPITAL CORPORATION
CONSOLIDATING BALANCE SHEET
ELIMINATING AND ADJUSTING ENTRIES

(a)	Common stock		$2,250,064	
		Accumulated deficit		$76,129
		Other assets		2,173,935

To eliminate PNW investment in subsidiaries

	Common Stock	Earnings/ Dividends	Total
APS	$1,793,627	$55,697	$1,849,324
SunCor	406,391	(116,159)	290,232
El Dorado	50,046	(15,667)	34,379
Total	$2,250,064	($76,129)	$2,173,935

(b)	Other current liabilities		$1,023	
		Customer and other receivables - net		$1,023

To eliminate intercompany receivables/payables

	A/R PNW	A/P Subs Books
APS	$636	$636
SunCor	381	381
El Dorado	6	6
Total	$ 1,023	$ 1,023

(c)	Other current liabilities		$128	
		Other current assets		$128

To eliminate PNW payable to APS

(d)	Minority interest-Suncor		$6,770	
		Real estate investments - net		$6,770

To eliminate minority interest of Suncor JV partners

(e)	Real estate investments - net		$6,892	
		Other - assets		$6,892

To reclass PNW capitalized interest related to SunCor

(f)	Deferred investment tax credit		$9,232	
		Other deferred debits		$9,232

To relcass PNW ITC

(g)	Accrued taxes		$1,276	
		Deferred income taxes		$1,276

To relcass PNW accrued taxes.

(h)	Other assets		$2,069	
		Customer and other receivables - net		$2,069

To reclass ELD Unity Note & interest to long term.

PINNACLE WEST CAPITAL CORPORATION
CONSOLIDATING INCOME STATEMENT
FOR THE YEAR ENDED DECEMBER 31, 1997
(THOUSANDS OF DOLLARS)

	PWCC	APS	SUNCOR	ELDO
OPERATING REVENUES:				
Electric		$ 1,878,553		
Real Estate			116,473	
Total	--	1,878,553	116,473	--
FUEL EXPENSES:				
Fuel for electric generation		201,341		
Purchased power		235,286		
Total	--	436,627	--	--
OPERATING EXPENSES:				
Utility operations and maintenance		399,434		
Real estate operations			111,112	
Depreciation and amortization	268	365,671	2,346	--
Taxes other than income taxes		120,259		
Total	268	885,364	113,458	--
OPERATING INCOME	(268)	556,562	3,015	--
OTHER INCOME (DEDUCTIONS):				
Allowance for equity funds used during construction		--		
Interest on long-term debt	(17,318)	(140,931)	(4,197)	--
Other interest	(1,478)	(17,195)	--	--
Capital interest		16,208		
Preferred stock dividend requirements		(12,803)		
Other - net	252,170	(9,827)	6,516	7,897
Total	233,374	(164,548)	2,319	7,897
INCOME BEFORE INCOME TAXES	233,106	392,014	5,334	7,897
Income Tax Expense (Benefit)	(2,750)	153,324		(293)
NET INCOME (LOSS)	$ 235,856	$ 238,690	$ 5,334	$ 8,190

	* E L I M I N A T I O N S * DEBIT	CREDIT	TOTAL
OPERATING REVENUES:			
Electric			$ 1,878,553
Real Estate			116,473
Total	--	--	1,995,026
FUEL EXPENSES:			
Fuel for electric generation			201,341
Purchased power			235,286
Total	--	--	436,627
OPERATING EXPENSES:			
Utility operations and maintenance			399,434
Real estate operations	1,776(b)	1,260(d)	111,628
Depreciation and amortization			368,285
Taxes other than income taxes	1,287(c,d)		121,546
Total	3,063	1,260	1,000,893
OPERATING INCOME	(3,063)	(1,260)	557,506
OTHER INCOME (DEDUCTIONS):			
Allowance for equity funds used during construction			--
Interest on long-term debt		1,776(b)	(160,670)
Other interest			(18,673)
Capital interest			16,208
Preferred stock dividend requirements			(12,803)
Other - net	252,214(a)	27(c)	4,569
Total	252,214	1,803	(171,369)
INCOME BEFORE INCOME TAXES	255,277	543	386,137
Income Tax Expense (Benefit)			150,281
NET INCOME (LOSS)	$ 255,277	$ 543	$ 235,856

PINNACLE WEST CAPITAL CORPORATION
CONSOLIDATING INCOME STATEMENT
ELIMINATING ENTRIES

(a)	Other - net (Subsiary income)	$252,214	
	Retained Earnings		$252,214

To eliminate PWCC Equity in earnings from subsidiairies

	PWCC
APS	238,690
SunCor	5,334
El Dorado	8,190
Total	252,214

(b)	Real Estate Operations	$1,776	
	Interest on long term debt		$1,776

To reclass Capitalized Interest for SunCor Land Sales.

(c)	Taxes other than income taxes	$27	
	Other - net		$27

To reclass PNW property taxes

(d)	Taxes other than income taxes	$1,260	
	Real estate operations		$1,260

To reclass SunCor property taxes

SUNCOR DEVELOPMENT COMPANY
CONSOLIDATING BALANCE SHEET
FOR THE MONTH ENDED DECEMBER 31, 1997

	ACCOUNT DESCRIPTION	SUNCOR CORPORATE	LPSCO	SUNCOR FARMING	SMLP	PVGC	HOMES	SUNCOR PALM VALLEY
	ASSETS:							
	CURRENT ASSETS							
	CASH AND SHORT TERM INVESTMENTS	3,847,842	316,271	100,708	864,098	(1,583)	(173,224)	406,000
1	ACCOUNTS RECEIVABLE	297,492	110,197	78,866	350,872	29,467	1,154,192	
	INTERCOMPANY ACCOUNTS:							
1	SASI	95						
1	LPSCO	91,260						
1	SMLP	18,788						
1	KABUTO JV							
1	PVGC					4,090,907		
1	SCM & GH - 129						(3,616,182)	
1	WWOS	12,397						
1	GOLDEN HERITAGE - GENERAL	421,643						
1	SCM-GENERAL	4,626,804						
1	HOMEBUILDING I/C INTEREST	1,345,579					(1,345,580)	
1	HOMEBUILDING CASH ADVANCES	8,996,796						
1	SUNRIDGE - DEVELOPMENT	86,771						
1	SUNRIDGE - GOLF	123,139						
1	SEDONA - DEVELOPMENT	23,754						
1	SEDONA - GOLF	92,155						
1	WIGWAM RESORT	302,257						
1	INTEREST RECEIVABLE	354,540						2,921
	NOTES RECEIVABLE	334,939			307,749			0
2	INVENTORIES					68,300		
2	PREPAID EXPENSES	38,272	21,863			46,503		2,028
	HOME INVENTORY	7,356					18,674,570	
	TOTAL CURRENT ASSETS	21,021,877	448,331	179,574	1,522,719	4,233,594	14,693,776	410,948

	ACCOUNT DESCRIPTION	WWOS	KABUTO JV	SUNCOR COMMERCIAL	H HILLS	R VIEJO
	ASSETS:					
	CURRENT ASSETS					
	CASH AND SHORT TERM INVESTMENTS	31,769	250	(326,546)		42,820
1	ACCOUNTS RECEIVABLE	96,566		122,241		
	INTERCOMPANY ACCOUNTS:					
1	SASI					
1	LPSCO					
1	SMLP					
1	KABUTO JV					
1	PVGC					
1	SCM & GH - 129					
1	WWOS					
1	GOLDEN HERITAGE - GENERAL					
1	SCM-GENERAL					
1	HOMEBUILDING I/C INTEREST					
1	HOMEBUILDING CASH ADVANCES					
1	SUNRIDGE - DEVELOPMENT					
1	SUNRIDGE - GOLF					
1	SEDONA - DEVELOPMENT					
1	SEDONA - GOLF					
1	WIGWAM RESORT					
1	INTEREST RECEIVABLE			5,605		223
	NOTES RECEIVABLE			915,763		
2	INVENTORIES			33,892		
2	PREPAID EXPENSES			0		
	HOME INVENTORY					
	TOTAL CURRENT ASSETS	128,335	250	750,955	0	43,042

	ACCOUNT DESCRIPTION	ELIMINATIONS REF	ELIMINATIONS DEBIT	ELIMINATIONS REF	ELIMINATIONS CREDIT	CONSOLIDATED
	ASSETS:					
	CURRENT ASSETS					
	CASH AND SHORT TERM INVESTMENTS					5,108,404
1	ACCOUNTS RECEIVABLE			J	158,000	2,081,894
	INTERCOMPANY ACCOUNTS:					
1	SASI			K	95	0
1	LPSCO			H	114,257	(22,997)
1	SMLP			J	18,788	0
1	KABUTO JV					0
1	PVGC			N	4,090,907	0
1	SCM & GH - 129	A	4,797,280	A	1,181,097	(0)
1	WWOS			Q	12,397	0
1	GOLDEN HERITAGE - GENERAL			A	421,643	0
1	SCM-GENERAL			A	4,626,804	0
1	HOMEBUILDING I/C INTEREST	C	1,345,580	C	1,345,580	(0)
1	HOMEBUILDING CASH ADVANCES			B	8,996,796	0
1	SUNRIDGE - DEVELOPMENT					86,771
1	SUNRIDGE - GOLF					123,139
1	SEDONA - DEVELOPMENT					23,754
1	SEDONA - GOLF					92,155

1	WIGWAM RESORT				302,257
1	INTEREST RECEIVABLE		P	101,480	261,807
	NOTES RECEIVABLE				1,558,451
2	INVENTORIES				102,192
2	PREPAID EXPENSES				108,666
	HOME INVENTORY		E	1,938,311	16,743,614
	TOTAL CURRENT ASSETS	6,142,859		23,006,155	26,570,106

	ACCOUNT DESCRIPTION	SUNCOR CORPORATE	LPSCO	SUNCOR FARMING	SMLP	PVGC	HOMES	SUNCOR PALM VALLEY
	LONG-TERM ASSETS							
	DEVELOPMENT PROJECTS							
	HIDDEN HILLS							
	RANCHO VIEJO							
	PALM VALLEY							177,275,730
	LITCHFIELD GREENS							2,277,974
	KABUTO JV							
	SCOTTSDALE MTN				8,838,343			
	MARKETPLACE - AUTOPLEX							
	TATUM RANCH	31,750,234						
	TALAVI							
	WIGWAM OUTLET STORES							
	GOLDEN HERITAGE LAND						895,891	
	BILTMORE ESTATES	41,893						
	EQUITY INVESTMENTS:							
	EQUITY IN CTRPT ASSOC-LLP	22,843,447						
	INVEST IN KYRENE ASSOCIATES LLC							
	INVEST IN PV APARTMENTS							1,368,213
	INVESTMENT IN SUNRIDGE CANYON LLC	11,218,584						
	INVESTMENT IN SEDONA GOLF LC	6,620,633						
	INVESTMENT IN PLUMCOR REALTY LLC							
	INVEST IN TALAVI ASSOCIATES LLC							
	CONSOLIDATED ELIMINATING ENTITIES:							
	INVEST IN KABUTO JV	5,797,485						
	INVESTMENT IN WIGWAM OUTLET LLC	4,455,629						
	INVEST IN SCOTTS MTN LTD PART	7,086,924						
	INVEST IN GOLDEN HERITAGE	151,062						
	GOLDEN HERITAGE DUE DILIGENCE	7,001						
	INVESTMENT IN SCM	483,214						
6	INVESTMENT IN LPSCO	8,368,589						
	INVESTMENT IN SASI							64,415
	INVESTMENT IN PALM VALLEY	181,041,431						

	ACCOUNT DESCRIPTION	WWOS	KABUTO JV	SUNCOR COMMERCIAL	H HILLS	R VIEJO
	LONG-TERM ASSETS					
	DEVELOPMENT PROJECTS					
	HIDDEN HILLS				478,017	
	RANCHO VIEJO					2,437,315
	PALM VALLEY			15,327,464		
	LITCHFIELD GREENS					
	KABUTO JV		12,617,550			
	SCOTTSDALE MTN					
	MARKETPLACE - AUTOPLEX			17,125,079		
	TATUM RANCH					
	TALAVI			3,492,629		
	WIGWAM OUTLET STORES	17,370,149				
	GOLDEN HERITAGE LAND					
	BILTMORE ESTATES					
	EQUITY INVESTMENTS:					
	EQUITY IN CTRPT ASSOC-LLP					
	INVEST IN KYRENE ASSOCIATES LLC			1,446,636		
	INVEST IN PV APARTMENTS					
	INVESTMENT IN SUNRIDGE CANYON LLC					
	INVESTMENT IN SEDONA GOLF LC					
	INVESTMENT IN PLUMCOR REALTY LLC			847,741		
	INVEST IN TALAVI ASSOCIATES LLC			2,325,106		
	CONSOLIDATED ELIMINATING ENTITIES:					
	INVEST IN KABUTO JV					
	INVESTMENT IN WIGWAM OUTLET LLC					
	INVEST IN SCOTTS MTN LTD PART					
	INVEST IN GOLDEN HERITAGE					
	GOLDEN HERITAGE DUE DILIGENCE					
	INVESTMENT IN SCM					
6	INVESTMENT IN LPSCO					
	INVESTMENT IN SASI					
	INVESTMENT IN PALM VALLEY					

		ELIMINATIONS				
	ACCOUNT DESCRIPTION	REF	DEBIT	REF	CREDIT	CONSOLIDATED
	LONG-TERM ASSETS					
	DEVELOPMENT PROJECTS					
	HIDDEN HILLS					478,017
	RANCHO VIEJO					2,437,315
	PALM VALLEY					192,603,194
	LITCHFIELD GREENS					2,277,974
	KABUTO JV					12,617,550
	SCOTTSDALE MTN					8,838,343
	MARKETPLACE - AUTOPLEX					17,125,079
	TATUM RANCH					31,750,234
	TALAVI					3,492,629
	WIGWAM OUTLET STORES					17,370,149
	GOLDEN HERITAGE LAND					895,891
	BILTMORE ESTATES					41,893
	EQUITY INVESTMENTS:					
	EQUITY IN CTRPT ASSOC-LLP					22,843,447

	INVEST IN KYRENE ASSOCIATES LLC						1,446,636
	INVEST IN PV APARTMENTS						1,368,213
	INVESTMENT IN SUNRIDGE CANYON LLC						11,218,584
	INVESTMENT IN SEDONA GOLF LC						6,620,633
	INVESTMENT IN PLUMCOR REALTY LLC						847,741
	INVEST IN TALAVI ASSOCIATES LLC						2,325,106
	CONSOLIDATED ELIMINATING ENTITIES:						0
	INVEST IN KABUTO JV			R	8,768,265		(2,970,780)
	INVESTMENT IN WIGWAM OUTLET LLC	O	17,498,042	O	23,026,125		(1,072,454)
	INVEST IN SCOTTS MTN LTD PART	I	10,764,769	I	17,905,448		(53,755)
	INVEST IN GOLDEN HERITAGE			D	151,062		0
	GOLDEN HERITAGE DUE DILIGENCE						7,001
	INVESTMENT IN SCM			D	483,214		0
6	INVESTMENT IN LPSCO			F	8,368,589		0
	INVESTMENT IN SASI	L	650,000	L	714,415		0
	INVESTMENT IN PALM VALLEY			V	181,041,431		0

	ACCOUNT DESCRIPTION	SUNCOR CORPORATE	LPSCO	SUNCOR FARMING	SMLP	PVGC
	INVESTMENT IN PALM VALLEY GOLF	6,359,255				
1	PALM VALLEY GOLF CONTRIB. CAP	(4,090,907)				
	PROJECT 2000:					
	INVESTMENT IN FIDDLESTICKS-SCOTTS	394,249				
	INVESTMENT IN FIDDLESTICKS-TEMPE	2,544,985				
	INVESTMENT IN FUNTASTICKS	3,444,214				
	INVESTMENT IN GENERAL COMM OPS	50,453,138				
	INVESTMENT IN PV MARKETPLACE	920,669				
	INVESTMENT IN PV PAVILIONS	671,963				
	INVESTMENT IN PV CROSSING	(151,342)				
	INVESTMENT IN AUTOPLEX	(244,933)				
	INVESTMENT IN TALAVI	(92,150)				
	INVESTMENT IN METROCENTER	123,793				
	INVESTMENT IN RESTORATION PLACE	(29,982)				
	INVESTMENT IN LITCHFIELD PARK OPS	30,064				
	INVESTMENT IN RANCHO VIEJO	2,420,586				
	INVESTMENT IN HIDDEN HILLS	477,117				
	COMMERCIAL PROPERTIES	0				5,431,977
	LONG-TERM NOTES RECEIVABLE	4,462,797				
	SDC PHASE I LAND NOTE TO WWOS	1,484,153				
	SDC PAYOFF OF WWOS RLC	10,000,000				
	SDC LOAN TO LPSCO	300,000				
	PROPERTY & EQUIPMENT, NET	605,533		36,696	1,082	102,799
3	DEFERRED ASSETS	2,621,179	885,811			230,331
	WATER, SEWER UTILITY PROP (NET)		9,768,026			
3	DEPOSITS					
	TOTAL LONG-TERM ASSETS	362,570,507	10,653,837	36,696	8,839,425	5,765,107
	TOTAL ASSETS	383,592,384	11,102,168	216,270	10,362,144	9,998,701

	ACCOUNT DESCRIPTION	HOMES	SUNCOR PALM VALLEY	WWOS	KABUTO JV	SUNCOR COMMERCIAL
	INVESTMENT IN PALM VALLEY GOLF					
1	PALM VALLEY GOLF CONTRIB. CAP					
	PROJECT 2000:					
	INVESTMENT IN FIDDLESTICKS-SCOTTS					
	INVESTMENT IN FIDDLESTICKS-TEMPE					
	INVESTMENT IN FUNTASTICKS					
	INVESTMENT IN GENERAL COMM OPS					
	INVESTMENT IN PV MARKETPLACE					
	INVESTMENT IN PV PAVILIONS					
	INVESTMENT IN PV CROSSING					
	INVESTMENT IN AUTOPLEX					
	INVESTMENT IN TALAVI					
	INVESTMENT IN METROCENTER					
	INVESTMENT IN RESTORATION PLACE					
	INVESTMENT IN LITCHFIELD PARK OPS					
	INVESTMENT IN RANCHO VIEJO					
	INVESTMENT IN HIDDEN HILLS					
	COMMERCIAL PROPERTIES					18,090,608
	LONG-TERM NOTES RECEIVABLE		459,833			
	SDC PHASE I LAND NOTE TO WWOS					
	SDC PAYOFF OF WWOS RLC					
	SDC LOAN TO LPSCO					
	PROPERTY & EQUIPMENT, NET	955,170	71,604	16,691		
3	DEFERRED ASSETS		145,380	236,504		187,249
	WATER, SEWER UTILITY PROP (NET)					
3	DEPOSITS	158,805				
	TOTAL LONG-TERM ASSETS	2,009,866	181,663,150	17,623,344	12,617,550	58,842,513
	TOTAL ASSETS	16,703,642	182,074,098	17,751,680	12,617,800	59,593,467

	ACCOUNT DESCRIPTION	H HILLS	R VIEJO	ELIMINATIONS REF	DEBIT	REF	CREDIT	CONSOLIDATED
	INVESTMENT IN PALM VALLEY GOLF					M	6,359,255	0
1	PALM VALLEY GOLF CONTRIB. CAP			N	4,090,907			0
	PROJECT 2000:							0
	INVESTMENT IN FIDDLESTICKS-SCOTTS			S	1,428,266	S	1,822,515	0
	INVESTMENT IN FIDDLESTICKS-TEMPE					S	2,544,985	0
	INVESTMENT IN FUNTASTICKS					S	3,444,214	0

	INVESTMENT IN GENERAL COMM OPS				S	890,859	S	51,343,998		0
	INVESTMENT IN PV MARKETPLACE						S	920,669		0
	INVESTMENT IN PV PAVILIONS						S	671,963		0
	INVESTMENT IN PV CROSSING				S	151,342				0
	INVESTMENT IN AUTOPLEX				S	244,933				0
	INVESTMENT IN TALAVI				S	92,150				0
	INVESTMENT IN METROCENTER						S	123,793		0
	INVESTMENT IN RESTORATION PLACE				S	29,982				0
	INVESTMENT IN LITCHFIELD PARK OPS						S	30,064		0
	INVESTMENT IN RANCHO VIEJO				U	23,942	U	2,444,528		0
	INVESTMENT IN HIDDEN HILLS				T	1,567	T	478,683		0
	COMMERCIAL PROPERTIES									23,522,585
	LONG-TERM NOTES RECEIVABLE									4,922,630
	SDC PHASE I LAND NOTE TO WWOS						P	1,484,153		0
	SDC PAYOFF OF WWOS RLC						P	10,000,000		0
	SDC LOAN TO LPSCO						G	300,000		0
	PROPERTY & EQUIPMENT, NET		8,298							1,797,872
3	DEFERRED ASSETS									4,306,454
	WATER, SEWER UTILITY PROP (NET)									9,768,026
3	DEPOSITS									158,805
	TOTAL LONG-TERM ASSETS	478,017	2,445,613			35,866,759		322,427,370		376,985,014
	TOTAL ASSETS	478,017	2,488,655			42,009,619		345,433,525		403,555,121

	ACCOUNT DESCRIPTION	SUNCOR CORPORATE	LPSCO	SUNCOR FARMING	SMLP	PVGC
	LIABILITIES:					
	CURRENT LIABILITIES					
4	A/P & RETENTION	38,723	104,211	30,761	13,467	32,464
4	ACCRUED LIABILITIES	1,926,954	120,572	61,648	146,177	56,920
	INTERCOMPANY ACCOUNTS:					
4	LPSCO - SDC		114,257			
4	SMLP - SDC				18,788	
4	SCM-SDC CASH ADVANCES 267					
4	GH-SDC INTERCO CAPITAL 265					
4	WWOS-SDC					
4	KABUTO JV-SDC					
	INTEREST PAYABLE	484,591				
	S/T NOTES PAYABLE OTHER					
	$45 MILLION TERM LOAN	3,005,169				
	$55 MILLION RLC					
	GOLDEN HERITAGE (PEW)					
	TEXTRON LOAN					
5	DEFERRED PROFIT	1,938,311		5,350	107,796	
	PWCC INTERCO PAYABLE	236,126				
	CUSTOMER DEPOSITS	0				
	TOTAL CURRENT LIABILITIES	7,629,874	339,040	97,759	286,228	89,384
	LONG-TERM LIABILITIES					
	LONG-TERM NOTES PAYABLE					
	WWOS OWES SDC PH I LAND NOTE					
	WWOS RLC PAYOFF BY SDC					
	CORPORATE TERM NOTE	$41,994,831				
	CORPORATE RLC	40,600,000				
	LPSCO OWES SDC		300,000			
	GOLDEN HERITAGE (PEW)					
	TEXTRON LOAN					3,550,062
6	OTHER ACCRUED LIABILITIES	3,124,805	585,186	54,096		
6	DEFERRED TAXES		238,404			
6	LONG-TERM CUSTOMER DEPOSITS		479,788			
6	CONTRIB PROPERTY AIA		999,073			
	DEFERRED CREDIT	11,000				
	TOTAL L/T LIABILITIES	85,730,636	2,602,451	54,096	0	3,550,062
	TOTAL LIABILITIES	93,360,510	2,941,491	151,855	286,228	3,639,446

	ACCOUNT DESCRIPTION	HOMES	SUNCOR PALM VALLEY	WWOS	KABITO JV	SUNCOR COMMERCIAL
	LIABILITIES:					
	CURRENT LIABILITIES					
4	A/P & RETENTION	2,110,634	748,284	625,567		244,648
4	ACCRUED LIABILITIES	410,842	122,084		15,000	1,066,471
	INTERCOMPANY ACCOUNTS:					
4	LPSCO - SDC					
4	SMLP - SDC					
4	SCM-SDC CASH ADVANCES 267	8,996,796				
4	GH-SDC INTERCO CAPITAL 265	1,432,265				
4	WWOS-SDC			12,397		
4	KABUTO JV-SDC					
	INTEREST PAYABLE	0		101,480		
	S/T NOTES PAYABLE OTHER					
	$45 MILLION TERM LOAN					
	$55 MILLION RLC					
	GOLDEN HERITAGE (PEW)	1,562,863				
	TEXTRON LOAN					
5	DEFERRED PROFIT		162,299			
	PWCC INTERCO PAYABLE					
	CUSTOMER DEPOSITS	1,555,966				
	TOTAL CURRENT LIABILITIES	16,069,366	1,032,667	739,444	15,000	1,311,120

	LONG-TERM LIABILITIES					
	LONG-TERM NOTES PAYABLE					
	WWOS OWES SDC PH I LAND NOTE			1,484,153		
	WWOS RLC PAYOFF BY SDC			10,000,000		
	CORPORATE TERM NOTE					
	CORPORATE RLC					
	LPSCO OWES SDC					
	GOLDEN HERITAGE (PEW)					
	TEXTRON LOAN					
6	OTHER ACCRUED LIABILITIES	0				217,679
6	DEFERRED TAXES					
6	LONG-TERM CUSTOMER DEPOSITS					
6	CONTRIB PROPERTY AIA					
	DEFERRED CREDIT					
	TOTAL L/T LIABILITIES	0	0	11,484,153	0	217,679
	TOTAL LIABILITIES	16,069,366	1,032,667	12,223,597	15,000	1,528,799

				ELIMINATIONS			
	ACCOUNT DESCRIPTION	H HILLS	R VIEJO	REF	DEBIT	REF CREDIT	CONSOLIDATED
	LIABILITIES:						
	CURRENT LIABILITIES						
4	A/P & RETENTION	900	32,301	J,K,A	158,095		3,823,866
4	ACCRUED LIABILITIES		35,768				3,962,437
	INTERCOMPANY ACCOUNTS:						
4	LPSCO - SDC			H	114,257		0
4	SMLP - SDC			J	18,788		0
4	SCM-SDC CASH ADVANCES 267			B	8,996,796		0
4	GH-SDC INTERCO CAPITAL 265			A	1,432,265		0
4	WWOS-SDC			Q	12,397		0
4	KABUTO JV-SDC						0
	INTEREST PAYABLE			P	101,480		484,591
	S/T NOTES PAYABLE OTHER						
	$45 MILLION TERM LOAN						3,005,169
	$55 MILLION RLC						0
	GOLDEN HERITAGE (PEW)						1,562,863
	TEXTRON LOAN					* 58,445	58,445
5	DEFERRED PROFIT			E	1,938,311		275,445
	PWCC INTERCO PAYABLE						236,126
	CUSTOMER DEPOSITS						1,555,966
X	TOTAL CURRENT LIABILITIES	900	68,069		12,772,389	58,445	14,964,908
	LONG-TERM LIABILITIES						
	LONG-TERM NOTES PAYABLE						
	WWOS OWES SDC PH I LAND NOTE			P	1,484,153		0
	WWOS RLC PAYOFF BY SDC			P	10,000,000		0
	CORPORATE TERM NOTE						41,994,831
	CORPORATE RLC						40,600,000
	LPSCO OWES SDC			G	300,000		0
	GOLDEN HERITAGE (PEW)						0
	TEXTRON LOAN			*	58,445		3,491,617
6	OTHER ACCRUED LIABILITIES						3,981,766
6	DEFERRED TAXES			F	207,912		30,492
6	LONG-TERM CUSTOMER DEPOSITS						479,788
6	CONTRIB PROPERTY AIA						999,073
	DEFERRED CREDIT						11,000
	TOTAL L/T LIABILITIES	0	0		12,050,510	0	91,588,567
	TOTAL LIABILITIES	900	68,069		24,822,899	58,445	106,553,475

ACCOUNT DESCRIPTION	SUNCOR CORPORATE	LPSCO	SUNCOR FARMING	SMLP	PVGC
MINORITY INTEREST					
EQUITY:					
SDC COMMON STOCK	1,022,000				
SDC ADDITIONAL PAID IN CAPITAL	405,368,522				
SDC EARNED SURPLUS-BEGINNING	(121,492,825)				
SDC EARNED SURPLUS-CURRENT	5,334,177				
SUBSIDIARY EARNINGS-CURRENT		29,982	(85,522)	2,907,503	(194,675)
SUBSIDIARY EQUITY:					
LPSCO		8,130,695			
SASI			149,937		
SMLP #3500				7,168,407	
PVGC					6,553,929
HOMEBUILDING					
PALM VALLEY #5500					
WWOS #4400					
KABUTO JV #3000					
COMMERCIAL PROPERTIES #2000					
HIDDEN HILLS #3300					
RANCHO SANTE FE #6600					
TOTAL EQUITY	290,231,874	8,160,677	64,415	10,075,910	6,359,255
TOTAL LIABILITIES AND EQUITY	383,592,384	11,102,168	216,270	10,362,144	9,998,701

ACCOUNT DESCRIPTION	HOMES	SUNCOR PALM VALLEY	WWOS	KABITO JV	SUNCOR COMMERCIAL
MINORITY INTEREST					
EQUITY:					
SDC COMMON STOCK					
SDC ADDITIONAL PAID IN CAPITAL					
SDC EARNED SURPLUS-BEGINNING					
SDC EARNED SURPLUS-CURRENT					
SUBSIDIARY EARNINGS-CURRENT	1,809,835	3,496,839	(831,462)	0	749,681
SUBSIDIARY EQUITY:					
LPSCO					
SASI					
SMLP #3500					
PVGC					
HOMEBUILDING	(1,175,560)				
PALM VALLEY #5500		177,544,592			
WWOS #4400			4,359,545		
KABUTO JV #3000				12,602,800	
COMMERCIAL PROPERTIES #2000					57,314,987
HIDDEN HILLS #3300					
RANCHO SANTE FE #6600					
TOTAL EQUITY	634,276	181,041,431	5,528,083	12,602,800	58,064,668
TOTAL LIABILITIES AND EQUITY	16,703,642	182,074,098	17,751,680	12,617,800	59,593,467

ACCOUNT DESCRIPTION	H HILLS	R VIEJO	ELIMINATIONS REF	DEBIT	REF	CREDIT
MINORITY INTEREST					I,R	6,769,772
EQUITY:						
SDC COMMON STOCK						
SDC ADDITIONAL PAID IN CAPITAL						
SDC EARNED SURPLUS-BEGINNING						
SDC EARNED SURPLUS-CURRENT						
SUBSIDIARY EARNINGS-CURRENT	(1,567)	(10,049)	D,F,I,M,S,V	8,799,172	L,O,T,U	928,599
SUBSIDIARY EQUITY:						
LPSCO			F	8,130,695		
SASI			L	799,937	L	650,000
SMLP #3500			I	23,244,640	I	16,076,233
PVGC			M	6,553,929		
HOMEBUILDING					D	1,175,560
PALM VALLEY #5500			V	177,544,592		
WWOS #4400			O	23,026,125	O	16,666,580
KABUTO JV #3000			R	12,602,800		
COMMERCIAL PROPERTIES #2000			S	57,572,455	S	257,868
HIDDEN HILLS #3300	478,683		T	478,683		
RANCHO SANTE FE #6600		2,430,635	U	2,444,528	U	13,893
TOTAL EQUITY	477,117	2,420,586		321,197,958		35,768,733
TOTAL LIABILITIES AND EQUITY	478,017	2,488,655		346,020,857		42,596,961

ACCOUNT DESCRIPTION	CONSOLIDATED
MINORITY INTEREST	6,769,772
EQUITY:	
SDC COMMON STOCK	1,022,000
SDC ADDITIONAL PAID IN CAPITAL	405,368,522
SDC EARNED SURPLUS-BEGINNING	(121,492,825)
SDC EARNED SURPLUS-CURRENT	5,334,177
SUBSIDIARY EARNINGS-CURRENT	0
SUBSIDIARY EQUITY:	
LPSCO	0
SASI	0
SMLP #3500	0
PVGC	0
HOMEBUILDING	0
PALM VALLEY #5500	0
WWOS #4400	0
KABUTO JV #3000	(0)
COMMERCIAL PROPERTIES #2000	0
HIDDEN HILLS #3300	0
RANCHO SANTE FE #6600	(0)
TOTAL EQUITY	290,231,874
TOTAL LIABILITIES AND EQUITY	403,555,121

* TO RECLASS CURRENT PORTION OF PVGC LOAN AS OF 12/31/97

SUNCOR DEVELOPMENT COMPANY
CONSOLIDATING BALANCE SHEET
DECEMBER 1997 CONSOLIDATING & ELIMINATING ENTRIES

		DEBIT	CREDIT
A.	SCM INTERCO A/P TO SDC	$4,797,280	
	GH INTERCO CAPITAL FROM SDC - ACQUISITION	$1,432,265	
	GH INTERCO A/P TO SDC		$1,181,097
	SDC A/R FROM GH		$421,643
	SDC A/R FROM SCM		$4,626,804
B.	HOMEBUILDING CASH ADVANCES FROM SDC	$8,996,796	
	SDC CASH ADVANCES TO HOMEBUILDING		$8,996,796
C.	SCM INTERCO CAPPED INTEREST	$1,345,580	
	SDC INTERCO INTEREST A/R FROM SCM		$1,345,580
	TO ELIMINATE INTERCO RECEIVABLES/PAYABLES BETWEEN HOMEBUILDING AND SDC		
D.	SDC INVESTMENT IN GH		$151,062
	SDC DUE DILIGENCE COSTS - GHH ACQUISITION		--
	SDC INVESTMENT IN SCM		$483,214
	HOMEBUILDING CURRENT YEAR INCOME	$1,809,835	
	HOMEBUILDING ACCUMULATED LOSSES		$1,175,560
	TO ELIMINATE INVESTMENT IN GH & SCM ON SDC BOOKS		
E.	DEFERRED INTERCO PROFIT	$1,938,311	
	HOME INVENTORY		$1,938,311
	TO ELIMINATE B/S GROSS UP ON INTERCO LOT SALES BETWEEN SDC AND HOMEBUILDING		
F.	LPSCO COMMON STOCK	$78,200	
	LPSCO PAID IN CAPITAL	$7,417,170	
	LPSCO EARNINGS - PRIOR	$635,325	
	SDC DEFERRED TAXES DIFFERENTIAL	$207,912	
	LPSCO EARNINGS - CURRENT YEAR	$29,982	
	SDC INVESTMENT IN LPSCO - CONTRIB CAPITAL		$7,495,370
	SDC INVESTMENT IN LPSCO - EARNINGS		$665,307
	SDC INVESTMENT IN LPSCO - DEFERRED TAXES DIFFERENTIAL		$207,912
	ELIMINATE SDC INVESTMENT IN LPSCO		
G.	LPSCO LONG-TERM NOTES PAYABLE	$300,000	
	SDC LONG-TERM NOTES RECEIVABLE		$300,000
	ELIMINATE LPSCO INTERCOMPANY NOTE WITH SDC		
H.	LPSCO ACCOUNTS PAYABLE	$114,257	
	SDC ACCOUNTS RECEIVABLE		$114,257
	ELIMINATE LPSCO INTERCOMPANY A/R WITH SDC		
I.	SMLP CONTRIBUTED CAPITAL-MINORITY INT		$5,311,464

		DEBIT	CREDIT
	SMLP CONTRIBUTED CAPITAL-SDC GP	$490,147	
	SMLP DISTRIBUTED CAPITAL-SDC GP		$6,059,112
	SMLP CONTRIBUTED CAPITAL-SDC LP	$2,100,000	
	SMLP DISTRIBUTED CAPITAL-SDC LP		$4,705,657
	SMLP EARNINGS - PRIOR	$20,654,493	
	SMLP EARNINGS - CURRENT YEAR	$2,907,509	
	MINORITY INTEREST CONTRIBUTED CAPITAL	$5,311,464	
	MINORITY INTEREST - PRIOR (35%)		$7,229,073
	MINORITY INTEREST - CURRENT YEAR (35%)		$1,017,628
	SDC INVESTMENT IN SMLP-LP		$2,100,000
	SDC DISTRIBUTIONS FROM SMLP-LP	$4,705,657	
	SDC INVESTMENT IN SMLP-GP		$490,147
	SDC DISTRIBUTIONS FROM SMLP -GP	$6,059,112	
	SDC INVESTMENT IN SMLP - EARNINGS		$15,315,301
	SDC LAND BASIS DIFFERENTIAL	--	
	ELIMINATE SDC INVESTMENT IN SMLP #3500		
J.	SMLP ACCOUNTS PAYABLE	$18,788	
	SDC ACCOUNTS RECEIVABLE		$18,788
	GH ACCOUNTS PAYABLE	$158,000	
	SMLP ACCOUNTS RECEIVABLE		$158,000
	ELIMINATE SMLP INTERCOMPANY A/R WITH SDC AND HOMEBUILDING (PREMIUMS)		
K.	SASI ACCOUNTS PAYABLE	$95	
	SDC ACCOUNTS RECEIVABLE		$95
	ELIMINATE SASI INTERCOMPANY A/R WITH SDC		
L.	SASI CONTRIBUTED CAPITAL	$339,023	
	SASI CAPITAL DISTRIBUTIONS		$650,000
	SASI EARNINGS - PRIOR	$460,914	
	SASI EARNINGS - CURRENT YEAR		$85,522
	PV INVESTMENT IN SASI - CONTRIB CAPITAL		$339,023
	PV INVESTMENT IN SASI - DISTRIBUTIONS	$650,000	
	PV INVESTMENT IN SASI - EARNINGS		$375,392
	ELIMINATE PALM VALLEY INVESTMENT IN SASI		
M.	PVGC CONTRIBUTED CAPITAL	$6,158,173	
	PVGC EARNINGS - PRIOR	$395,756	
	PVGC EARNINGS - CURRENT YEAR	($194,675)	
	SDC INVESTMENT IN PVGC - EARNINGS		$201,082
	SDC INVESTMENT IN PVGC - CONTRIB CAPITAL		$6,158,173
	ELIMINATE SDC INVESTMENT IN PALM VALLEY GOLF		
N.	SDC CONTRIB. CAPITAL TO PVGC	$4,090,907	
	PVGC ACCOUNTS RECEIVABLE		$4,090,907

		DEBIT	CREDIT
	ELIMINATE PVGC INTERCOMPANY A/R WITH SDC		
O.	WWOS CONTRIBUTED CAPITAL-PHASE 1	$9,500,000	
	WWOS CONTRIBUTED CAPITAL-PHASE 2	$13,526,125	
	WWOS EARNINGS - PRIOR		$1,101,590
	WWOS EARNINGS - CURRENT YEAR		$831,462
	WWOS CAPITAL DISTRIBUTIONS-PHASE 1		$9,500,000
	WWOS CAPITAL DISTRIBUTIONS-PHASE 2		$4,967,126
	WWOS PREFERRED RETURN-PHASE 1		$287,568
	WWOS PREFERRED RETURN-PHASE 2		$810,296
	SDC INVESTMENT IN WWOS -PHASE 1		$9,500,000
	SDC INVESTMENT IN WWOS -PHASE 2		$13,526,125
	SDC INVESTMENT IN WWOS - EARNINGS	$1,933,052	
	SDC DISTRIBUTIONS FROM WWOS-PHASE 1	$9,500,000	
	SDC DISTRIBUTIONS FROM WWOS-PHASE 2	$4,967,126	
	SDC PREFERRED RETURN -PHASE 1	$287,568	
	SDC PREFERRED RETURN -PHASE 2	$810,296	
	SDC BASIS DIFFERENTIAL PH I BUILDINGS	--	
	SDC BASIS DIFFERENTIAL PH I LAND	--	
	SDC BASIS DIFFERENTIAL PH II LAND	--	
	SDC 1994 CAPPED INTEREST ON WWOS		--
	SDC 1995 DEVELOPMENT FEES		--
	ELIMINATE SDC INVESTMENT IN WIGWAM OUTLET STORES #4400		
P.	WWOS INTEREST PAYABLE	$33,668	
	WWOS INTEREST PAYABLE	$67,813	
	SDC INTEREST RECEIVABLE		$33,668
	SDC INTEREST RECEIVABLE		$67,813
	WWOS NOTES PAYABLE	$1,484,153	
	SDC NOTES RECEIVABLE		$1,484,153
	WWOS NOTES PAYABLE	$10,000,000	
	SDC NOTES RECEIVABLE		$10,000,000
	ELIMINATE WWOS INTERCOMPANY NOTES AND INTEREST WITH SDC		
Q.	WWOS ACCOUNTS PAYABLE	$12,397	
	SDC ACCOUNTS RECEIVABLE		$12,397
	ELIMINATE WWOS INTERCOMPANY A/R WITH SDC		
R.	KABUTO CONTRIBUTED CAPITAL - SDC	$8,768,265	
	KABUTO CONTRIBUTED CAPITAL - KABUTO	$3,834,535	
	MINORITY INTEREST		$3,834,535
	SDC INVESTMENT IN KABUTO - CONTR CAPITAL		$5,914,509
	BALANCING PLUG		$2,853,757
	SDC BASIS DIFFERENTIAL IN LAND	--	
	SDC DEVELOPMENT COSTS		--

		DEBIT	CREDIT
	ELIMINATE SDC INVESTMENT IN KABUTO JV #3000		
S.	COMMERCIAL OPS CONTRIBUTED CAPITAL	$57,572,855	
	COMMERCIAL EARNINGS - PRIOR		$257,868
	COMMERCIAL EARNINGS - CURRENT YEAR	$749,681	
	SDC INVEST IN GEN COMMERCIAL OPS - EARNINGS	$890,859	
	SDC INVEST IN GEN COMMERCIAL OPS - CONT CAPITAL		$51,343,998
	SDC INVESTMENT IN OUTER LIMITS - PURCHASE		$1,822,515
	SDC INVESTMENT IN FIDDLE (SCOTTS) - CONT CAPITAL	$1,090,059	
	SDC INVESTMENT IN FIDDLE (SCOTTS) - EARNINGS	$338,207	
	SDC INVESTMENT IN FUNTASTICKS - CONT CAPITAL		$3,282,433
	SDC INVESTMENT IN FUNTASTICKS - EARNINGS		$161,781
	SDC INVESTMENT IN FIDDLE (TEMPE) - CONT CAPITAL		$2,213,969
	SDC INVESTMENT IN FIDDLE (TEMPE) - EARNINGS		$331,016
	SDC INVESTMENT IN PV MARKETPLACE - EARNINGS		$920,669
	SDC INVESTMENT IN PV PAVILIONS - EARNINGS		$671,963
	SDC INVESTMENT IN PV CROSSING - EARNINGS	$151,342	
	SDC INVESTMENT IN METROCENTER - EARNINGS		$123,793
	SDC INVESTMENT IN REST PLACE - EARNINGS	$29,982	
	SDC INVESTMENT IN LITCHFIELD OTHER - EARNINGS		$30,064
	SDC INVESTMENT IN AUTOPLEX - EARNINGS	$244,933	
	SDC INVESTMENT IN TALAVI - EARNINGS	$92,150	
	ELIMINATE SDC INVESTMENT IN COMMERCIAL OPERATIONS #2000		
T.	HIDDEN HILLS CONTRIBUTED CAPITAL	$478,683	
	HIDDEN HILLS EARNINGS - PRIOR		$0
	HIDDEN HILLS EARNINGS - CURRENT YEAR		$1,567
	SDC INVESTMENT IN HIDDEN HILLS - EARNINGS	$1,567	
	SDC INVESTMENT IN HIDDEN HILLS - CONT CAPITAL		$478,683
	ELIMINATE SDC INVESTMENT IN HIDDEN HILLS JV #3300		
U.	SDC INVESTMENT IN RANCHO VIEJO - EARNINGS	$23,942	
	SDC INVESTMENT IN RANCHO VIEJO - CAPITAL		$2,444,528
	RANCHO VIEJO CONTRIBUTED CAPITAL	$2,444,528	
	RANCHO VIEJO EARNINGS - PRIOR		$13,893
	RANCHO VIEJO EARNINGS - CURRENT YEAR		$10,049
	ELIMINATE SDC INVESTMENT IN RANCHO VIEJO JV #6600		
V.	PV CONTRIBUTED CAPITAL	$177,544,592	
	PV EARNINGS - PRIOR	$0	
	PV EARNINGS - CURRENT YEAR	$3,496,839	
	SDC INVESTMENT IN PALM VALLEY - EARNINGS		$3,496,839
	SDC INVESTMENT IN PALM VALLEY - DEVELOP		$177,544,592
	ELIMINATE SDC INVESTMENT IN PALM VALLEY #5500		
	TOTAL	$372,755,514	$372,755,514

SUNCOR DEVELOPMENT COMPANY
CONSOLIDATING INCOME STATEMENT
FOR THE YEAR ENDING DECEMBER 31, 1997

ACCOUNT DESCRIPTION	SUNCOR	LPSCO	SCTS MTN	PVOC	G H HOMES	WWOS
REVENUES:						
SALE OF ASSETS	$6,000,000	-	-	-	-	-
DEFERRED PROFIT	-	-	279,896	-	-	-
LAND SALES	40,827,538	-	4,876,887	-	-	-
HOME SALES	-	-	-	-	58,111,924	-
COMMERCIAL PROPERTIES	5,975,257	-	-	2,194,091	-	2,322,774
UTILITY SALES	-	1,618,907	-	-	-	-
MANAGEMENT FEES	1,149,442	-	-	-	-	-
TOTAL OPERATING REVENUES	53,952,237	1,618,907	5,156,783	2,194,091	58,111,924	2,322,774
OPERATING EXPENSES						
COST OF ASSETS SOLD	5,043,300	-	-	-	-	-
COST OF LAND SOLD	33,564,613	-	2,079,251	-	-	-
COST OF HOMES SOLD	(2,322,193)	-	-	-	50,970,298	-
LAND PROJECT COSTS	2,118,718	-	239,337	-	-	-
COMMERCIAL PROPERTIES	4,498,370	-	-	1,725,179	-	1,072,563
GENERAL & ADMINISTRATIVE	9,882,277	-	204,301	-	4,909,682	-
UTILITY EXPENSE	-	1,397,097	-	-	-	-
RESORT OPERATIONS	10,202	-	-	-	-	-
DEPRECIATION & AMORTIZATION	716,227	178,950	563	158,207	336,901	954,720
TOTAL OPERATING EXPENSES	53,511,514	1,576,047	2,523,452	1,883,386	56,216,881	2,027,283
NET OPERATING INCOME	440,723	42,860	2,633,331	310,705	1,895,043	295,491
OTHER INCOME AND GAINS:						
EQUITY IN JOINT VENTURES	3,182,361	-	-	-	-	-
INTEREST INCOME	857,924	14,466	281,535	-	-	19,422
OTHER	-	-	-	-	49,269	-
TOTAL OTHER INCOME AND GAINS	4,040,285	14,466	281,535	-	49,269	19,422
INTEREST EXPENSE						
INTEREST EXPENSE	5,870,928	27,340	7,357	505,378	134,477	1,146,375
LESS: CAPITALIZED INTEREST	(3,494,746)	-	-	-	-	-
TOTAL INTEREST EXPENSE	2,376,182	27,340	7,357	505,378	134,477	1,146,375
NET INCOME BEFORE MINORITY INTEREST	2,104,825	29,986	2,907,509	(194,673)	1,809,835	(831,462)
MINORITY INTEREST	480,231	-	-	-	-	-
NET INCOME/(LOSS)	$1,624,594	$29,986	$2,907,509	($194,673)	$1,809,835	($831,462)

ACCOUNT DESCRIPTION	HIDDEN HILLS	RANCHO VIEJO	ELIMINATING ENTRIES	CONSOLIDATED INCOME
REVENUES:				
SALE OF ASSETS	-	-	-	$6,000,000
DEFERRED PROFIT	-	-	-	279,896
LAND SALES	-	265,847	-	45,970,272
HOME SALES	-	-	-	58,111,924
COMMERCIAL PROPERTIES	-	-	-	10,492,122
UTILITY SALES	-	-	-	1,618,907
MANAGEMENT FEES	-	-	-	1,149,442
TOTAL OPERATING REVENUES	-	265,847	-	123,622,563
OPERATING EXPENSES				
COST OF ASSETS SOLD	-	-	-	5,043,300
COST OF LAND SOLD	-	220,328	-	35,864,192
COST OF HOMES SOLD	-	-	-	48,648,105
LAND PROJECT COSTS	290	60,945	-	2,419,290
COMMERCIAL PROPERTIES	-	-	-	7,296,112
GENERAL & ADMINISTRATIVE	1,277	-	-	15,057,115
UTILITY EXPENSE	-	-	-	1,337,519
RESORT OPERATIONS	-	-	-	10,202
DEPRECIATION & AMORTIZATION	-	398	-	2,345,966
TOTAL OPERATING EXPENSES	1,567	281,671	-	118,021,801
NET OPERATING INCOME	(1,567)	(15,824)	-	5,600,762
OTHER INCOME AND GAINS:				
EQUITY IN JOINT VENTURES	-	-	-	3,182,361
INTEREST INCOME	-	5,775	-	1,179,122
OTHER	-	-	-	49,269
TOTAL OTHER INCOME AND GAINS	-	5,775	-	4,410,752
INTEREST EXPENSE				
INTEREST EXPENSE	-	-	-	7,691,855
LESS: CAPITALIZED INTEREST	-	-	-	(3,494,746)
TOTAL INTEREST EXPENSE	-	-	-	4,197,109
NET INCOME BEFORE MINORITY INTEREST	(1,567)	(10,049)	-	5,814,405
MINORITY INTEREST	-	-	-	480,231
NET INCOME/(LOSS)	($1,567)	($10,049)	-	$5,334,174

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Company: PINNACLE WEST CAPITAL CORP
Form Type: U-3A-2 SEC File #: 069-00306
Description: FORM U-3A-2
SEC File Date: 02/28/97

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Adopted November 9, 1939 File No. 69-306

SECURITIES AND EXCHANGE COMMISSION
Washington, D.C.

FORM U-3A-2

Statement by Holding Company
Claiming Exemption under Rule U-2
from the Provisions of the
Public Utility Holding Company Act of 1935

To Be Filed Annually Prior to March 1

Pinnacle West Capital Corporation

(Name of Company)

hereby files with the Securities and Exchange Commission, pursuant to Rule 2, its statement claiming exemption as a holding company from the provisions of the Public Utility Holding Company Act of 1935, and submits the following information:

1. Name, state of organization, location and nature of business of Claimant and every subsidiary thereof, other than any exempt wholesale generator (EWG) or foreign utility company in which Claimant directly or indirectly holds an interest.

Pinnacle West Capital Corporation ("Claimant"), having been incorporated on February 20, 1985 under the laws of the State of Arizona, and having its principal executive offices at 400 East Van Buren, Suite 700, Phoenix, Arizona 85004, was organized principally to acquire and hold securities of other corporations for investment purposes. Claimant currently holds stock in the following subsidiaries:

a. Arizona Public Service Company ("APS" or the "Company"), is engaged principally in serving electricity in the State of Arizona. Incorporated in 1920 under the laws of the State of Arizona and having its principal executive offices at 400 North Fifth Street, Phoenix, Arizona 85004, APS became a subsidiary of the Claimant pursuant to a corporate restructuring plan approved by the Company's shareholders on April 18, 1985.

(1) AXIOM Power Solutions, Inc. ("AXIOM") -- an Arizona corporation having been incorporated on October 29, 1996 and having its principal executive offices at 400 E. Van Buren, Phoenix, Arizona 85004, was organized primarily to sell security and energy management products and services. AXIOM is a wholly-owned subsidiary of APS.

(2) Bixco, Inc. ("Bixco") -- an Arizona corporation having been incorporated on June 4, 1971 and having its principal executive offices at 400 North Fifth Street, Phoenix, Arizona 85004, was organized primarily to conduct exploration activities for energy resources and other valuable minerals. Subsequent to the sale of its oil and natural gas properties in 1981, Bixco has been inactive. Bixco is a wholly-owned subsidiary of APS.

b. SunCor Development Company ("SunCor") -- an Arizona corporation having been incorporated on June 30, 1965 and having its principal executive offices at 3838 North Central Avenue, Suite 1500, Phoenix, Arizona 85012, is a wholly-owned subsidiary of Claimant engaged primarily in the owning, holding and development of real property.

(1) SunCor Resort & Golf Management, Inc. ("Resort & Golf Management") (previously named "SunCor Resort Management, Inc." and "SunCor Farms, Inc.") -- an Arizona corporation having been incorporated on December 31, 1986 and having its principal executive offices at 3838 North Central Avenue, Suite 1500, Phoenix, Arizona 85012 operates and manages hotel, golf, food and beverage for the Wigwam Resort and Country Club, Sedona Golf Resort, SunRidge Canyon Golf Club, Real del Mar Golf Club, and Palm Valley Golf Club. Resort & Golf Management is a wholly-owned subsidiary of SunCor.

(2) Litchfield Park Service Company ("LPSCO") -- an Arizona corporation having been incorporated on September 21, 1954 and having its principal executive offices at 501 East Plaza Circle, Suite B, Litchfield Park, Arizona 85340, is a regulated public utility engaged in providing water and sewer services to commercial and residential customers. LPSCO became a wholly-owned subsidiary of SunCor on December 31, 1986.

(3) SunCor Homes, Inc. ("SunCor Homes") -- (previously named "LGR, Inc." and "WGP Realty, Inc.") an Arizona corporation having been incorporated on May 14, 1986 and having its principal executive offices at 3838 North Central Avenue, Suite 1500, Phoenix, Arizona 85012, was organized to provide brokerage and realty services in the sale of commercial and residential real property. SunCor Homes is a wholly-owned subsidiary of SunCor.

(i) Golden Heritage Construction, Inc. ("Golden Heritage") -- an Arizona corporation having been incorporated on December 30, 1993 and having its principal executive offices at 7975 North Hayden Rd. Suite D-280, Scottsdale, Arizona 85258, was organized to serve as a general residential contractor. Golden Heritage became a wholly-owned subsidiary of SunCor Homes, Inc. on January 1, 1996.

(4) SCM, Inc. ("SCM") -- an Arizona corporation having been incorporated on May 14, 1991 and having its principal executive offices at 3838 North Central Avenue,

Suite 1500, Phoenix, Arizona 85012, was organized to participate in real estate joint ventures and other real estate related activities. SCM is a wholly-owned subsidiary of SunCor.

(5) Golf de Mexico, S.A. DE C.V. ("Golf de Mexico") -- a Mexican variable capital corporation having been incorporated on February 8, 1992 in Tijuana, Baja California, Mexico, and having its principal executive offices at 3838 North Central Avenue, Suite 1500, Phoenix, Arizona 85012, was organized to operate and manage the Real del Mar Golf Course in Mexico.

(6) SunCor Realty & Management Company ("SunCor Realty") -- (previously named Russell Ranch Development Company) an Arizona corporation having been incorporated on April 1, 1994 and having its principal executive offices at 3838 North Central Avenue, Suite 1500, Phoenix, Arizona 85012 was organized to participate in real estate joint ventures and other real estate related activities. SunCor Realty is a wholly-owned subsidiary of SunCor.

(7) Palm Valley Golf Club, Inc. ("Palm Valley Golf") -- an Arizona corporation having been incorporated on January 23, 1996 and having its principal executive offices at 3838 North Central Avenue, Suite 1500, Phoenix, Arizona 85012 was organized to hold title to the Palm Valley Golf Course. Palm Valley Golf is a wholly-owned subsidiary of SunCor.

(8) Rancho Viejo de Santa Fe, Inc. ("Rancho Viejo") -- a New Mexico corporation having been incorporated on March 18, 1996 and having its principal executive offices at 3838 North Central Avenue, Suite 1500, Phoenix, Arizona 85012 was organized to engage in real estate development in New Mexico. Rancho Viego is a wholly-owned subsidiary of SunCor.

c. El Dorado Investment Company -- an Arizona corporation having been incorporated on July 27, 1983 and having its principal executive offices at 400 East Van Buren, Suite 750, Phoenix, Arizona 85004, is a wholly-owned subsidiary of Claimant engaged primarily in the acquisition and holding of stocks and securities of other companies for investment purposes.

2. A brief description of the properties of Claimant and each of its subsidiary public utility companies used for the generation, transmission and distribution of electric energy for sale, or for the production, transmission and distribution of natural or manufactured gas, indicating the location of principal generating plants, transmission lines, producing fields, gas manufacturing plants and electric and gas distribution facilities, including all such properties which are outside the state in which Claimant and its subsidiaries are organized and all transmission or pipelines which deliver or receive electric energy or gas at the borders of such state.

Neither the Claimant nor any of its subsidiaries own property used for the production, transmission and distribution of natural or manufactured gas. APS, a "public utility company" as that term is defined in the Public Utility Holding Company Act of 1935, is the only one of Claimant's subsidiaries that owns property used for the generation, transmission and distribution of electric energy for sale.

Exhibit D attached hereto shows the location of APS' major generating plants (including those owned jointly with others), principal transmission lines (including those operated for others) and interconnections of transmission lines with out-of-state utilities at state lines. All of such facilities, except the Four Corners Generating Station ("Four Corners"), and all of APS' distribution facilities, are located within the State of Arizona. Four Corners is a mine-mouth power plant, located in the northwest corner of New Mexico, near the city of Farmington, approximately 40 miles east of the Arizona-New Mexico border.

APS' present generating facilities have an accredited capacity aggregating 4,039,220 kilowatts, comprised as follows:

	Capacity
Coal:	
Units 1, 2 and 3 at Four Corners, aggregating	560,000 kw
15% owned Units 4 and 5 at Four Corners, representing	222,000
Units 1, 2, and 3 at the Cholla Plant, aggregating	615,000
14% owned Units 1, 2 and 3 at the Navajo Plant, representing	315,000
	1,712,000 kw
Gas or Oil:	
Two steam units at Ocotillo, two steam units at Saguaro and one steam unit at Yucca, aggregating	463,400 kw(1)
Eleven combustion turbine units, aggregating	500,600
Three combined cycle units, aggregating	253,500
	1,217,500 kw
Nuclear:	
29.1% owned or leased Units 1, 2 and 3 at Palo Verde, representing	1,105,520 kw
Other	4,200 kw

(1) West Phoenix steam units (96,300) are currently mothballed.

APS' transmission facilities consist of approximately 4,862 pole miles of overhead lines and approximately 18 miles of underground lines, all of which are located within the State of Arizona. APS' distribution facilities consist of approximately 11,335 pole miles of overhead lines and approximately 8,993 miles of underground lines, all of which are located within the State of Arizona.

3. The following information for the last calendar year with respect to Claimant and each of its subsidiary public utility companies:

a. Number of kwh of electric energy sold at retail or wholesale.

Claimant	APS
None	22,387,930,000 kwh of electric energy sold at wholesale or retail

b. Number of kwh of electric energy distributed at retail outside the state in which each such company is organized.

Claimant	APS
None	62,766,000 kwh of electric energy distributed at retail outside Arizona

c. Number of kwh of electric energy sold at wholesale outside the state in which each such company is organized, or at the state line.

Claimant	APS
None	973,300 kwh of electric energy sold at wholesale outside Arizona or at state line

d. Number of kwh of electric energy purchased outside the state in which each such company is organized or at the state line.

Claimant	APS
None	4,605,356 kwh of electric energy purchased outside Arizona or at state line

4. The following information for the reporting period with respect to Claimant and each interest it holds directly or indirectly in an EWG or a foreign utility company, stating monetary amounts in United States dollars:

The Claimant holds no interest, direct or indirect, in an EWG or a foreign utility company.

a. Name, location, business address and description of the facilities used by the EWG or foreign utility company for the generation, transmission and distribution of electric energy for sale or for the distribution at retail of natural or manufactured gas.

Not applicable.

b. Name of each system company that holds an interest in such EWG or foreign utility company; and description of the interest held.

Not applicable.

c. Type and amount of capital invested, directly or indirectly, by the holding company claiming exemption; any direct or indirect guarantee of the security of the EWG or foreign utility company by the holding company claiming exemption; and any debt or other financial obligation for which there is recourse, directly or indirectly, to the holding company claiming exemption or another system company, other than the EWG or foreign utility company.

Not applicable.

d. Capitalization and earnings of the EWG or foreign utility company during the reporting period.

Not applicable.

e. Identify any service, sales or construction contract(s) between the EWG or foreign utility company and a system company, and describe the services to be rendered or goods sold and fees or revenues under such agreement(s).

Not applicable.

EXHIBIT A

A consolidating statement of income and surplus of the Claimant and its subsidiary companies for the last calendar year, together with a consolidating balance sheet of Claimant and its subsidiary companies as of the close of such calendar year.

Exhibit A hereto includes consolidating statements of income and consolidating balance sheets for the Claimant and the following of its subsidiaries: Arizona Public Service Company, SunCor Development Company and El Dorado Investment Company. Subsidiaries have been consolidated for financial reporting purposes in accordance with Statement of Financial Accounting Standards No. 94, Consolidation of All Majority-Owned Subsidiaries. Also included are consolidating statements of income and consolidating balance sheets for SunCor Development Company and its subsidiaries.

EXHIBIT B FINANCIAL DATA STATEMENT

If, at the time a report on this form is filed, the registrant is required to submit this report and any amendments thereto electronically via EDGAR, the registrant shall furnish a Financial Data Schedule. The Schedule shall set forth the financial and other data specified below that are applicable to the registrant on a consolidated basis.

1. Total Assets.

2. Total Operating Revenues.

3. Net Income.

See Exhibit B hereto.

EXHIBIT C

An organizational chart showing the relationship of each EWG or foreign utility company to associate companies in the holding-company system.

Not applicable.

EXHIBIT D

Exhibit D is a map of the state of Arizona showing the following:

APS Service Area;
Major APS Power Plants, including joint ownership;
Principal APS Transmission Lines;
and Transmission Lines Operated for Others.

The above-named Claimant has caused this statement to be duly executed on its behalf by its authorized officer on this 28th day of February, 1997.

Pinnacle West Capital Corporation

(Name of Claimant)

By /s/ Michael S. Ash

Michael S. Ash
Corporate Counsel

[CORPORATE SEAL]

Attest:

/s/Suzanne Debes

Suzanne Debes
Associate Secretary

Name, title and address of officer to whom notices and correspondence concerning this statement should be addressed:

Michael S. Ash	Corporate Counsel	(Name)	(Title)
400 East Van Buren, Suite 700, Phoenix, Arizona 85004		(Address)	

PINNACLE WEST CAPITAL CORPORATION
CONSOLIDATING INCOME STATEMENT
FOR THE YEAR ENDED DECEMBER 31, 1996
(THOUSANDS OF DOLLARS)

	PWCC	APS	SUNCOR	ELDO
OPERATING REVENUES:				
Electric		$1,718,272		
Real Estate			99,488	
Total	--	1,718,272	99,488	--
FUEL EXPENSES:				
Fuel for electric generation		230,393		
Purchased power		95,130		
Total	--	325,523	--	--
OPERATING EXPENSES:				
Utility operations and maintenance		430,714		
Real estate operations			94,874	
Depreciation and amortization	216	297,210	2,081	--
Taxes other than income taxes	33	121,104	940	
Total	249	849,028	97,895	--
OPERATING INCOME	(249)	543,721	1,593	--
OTHER INCOME (DEDUCTIONS):				
Allowance for equity funds used during construction		5,209		
Interest on long-term debt	(22,208)	(147,666)	(2,790)	--
Other interest	(4,967)	(18,797)	--	--
Allowance for borrowed funds used during construction		9,509		
Preferred stock dividend requirements		(17,092)		
Other, net	233,977	(15,544)	5,351	372
Total	206,802	(184,381)	2,561	372
INCOME FROM CONTINUING OPERATIONS BEFORE INCOME TAXES	206,553	359,340	4,154	372
Income Tax Benefits (Expense)	4,506	(132,961)		(1)
INCOME FROM CONTINUING OPERATIONS	211,059	226,379	4,154	371
DISCONTINUED OPERATIONS, NET OF TAX	(9,539)			
EXTRAORDINARY ITEM FOR EARLY RETIREMENT OF DEBT, NET OF TAX	(20,340)			
NET INCOME (LOSS)	$ 181,180	$ 226,379	$ 4,154	$ 371

	* E L I M I N A T I O N S * DEBIT		CREDIT		TOTAL
OPERATING REVENUES:					
Electric					$ 1,718,272
Real Estate					99,488
Total	--		--		1,817,760
FUEL EXPENSES:					
Fuel for electric generation					230,393
Purchased power					95,130
Total	--		--		325,523
OPERATING EXPENSES:					
Utility operations and maintenance					430,714
Real estate operations	1,206	(c)			96,080
Depreciation and amortization					299,507
Taxes other than income taxes					122,077
Total	1,206		--		948,378
OPERATING INCOME	(1,206)		--		543,859
OTHER INCOME (DEDUCTIONS):					
Allowance for equity funds used during construction					5,209
Interest on long-term debt			1,206	(c)	(171,458)
Other interest			--	(b)	(23,764)
Allowance for borrowed funds used during construction					9,509
Preferred stock dividend requirements					(17,092)
Other, net	230,904	(a,b)			(6,748)
Total	230,904		1,206		(204,344)
INCOME FROM CONTINUING OPERATIONS BEFORE INCOME TAXES	229,698		1,206		339,515
Income Tax Benefits (Expense)					(128,456)
INCOME FROM CONTINUING OPERATIONS	229,698		1,206		211,059
DISCONTINUED OPERATIONS, NET OF TAX					(9,539)
EXTRAORDINARY ITEM FOR EARLY RETIREMENT OF DEBT, NET OF TAX					(20,340)
NET INCOME (LOSS)	$ 229,698		$ 1,206		$ 181,180

PINNACLE WEST CAPITAL CORPORATION
CONSOLIDATING INCOME STATEMENT
ELIMINATING ENTRIES

(a)	Income from Subsidiaries	$ 230,904		
	Retained Earnings		$	230,904

To eliminate PWCC Equity in earnings from subsidiairies

	PWCC
APS	226,379
SUNCOR	4,154
EL DORADO	371
	230,904

(b)	Interest Income (SunCor)	$ --		
	Interest Expense (El Dorado)		$	--

To eliminate SunCor interest charges to El Dorado.

(c)	Real Estate Operations	$ 1,206		
	Interest Expense (PWCC)		$	1,206

To reclass Capitalized Interest for SunCor Land Sales.

PINNACLE WEST CAPITAL CORPORATION
CONSOLIDATING BALANCE SHEET
December 31, 1996
(THOUSANDS OF DOLLARS)

	PWCC	APS	SUNCOR	ELDO
A S S E T S				
CURRENT ASSETS				
Cash and cash equivalents	$ 4,485	$ 12,521	$ 6,225	$ 3,455
Customer and other receivables - net	572	159,928	7,416	1,893
Accrued utility revenue		55,470		
Materials and supplies		74,120		
Fossil fuel		13,928		
Deferred income taxes	61,264	8,424		
Other current assets	314	22,767	18,150	--
Total current assets	66,635	347,158	31,791	5,348
INVESTMENTS AND OTHER ASSETS				
Real estate investments, net (cap interest)	8,668		398,809	
Other assets	2,111,100	113,666	5,861	33,459
Total investments and other	2,119,768	113,666	404,670	33,459
UTILITY PLANT				
Electric plant in service and held for future use		6,803,211		
Less accumulated depreciation and amortization		2,426,143		
Total	--	4,377,068	--	--
Construction work in progress		226,935		
Nuclear Fuel		51,137		
Net Utility Plant	--	4,655,140	--	--
DEFERRED DEBITS				
Regulatory asset for income taxes	--	516,722		
Rate synchronization deferral		414,082		
Other deferred debits	69	376,454	4,917	
Total deferred debits	69	1,307,258	4,917	--
TOTAL ASSETS	$ 2,186,472	$ 6,423,222	$ 441,378	$ 38,807

	ELIMINATIONS AND ADJUSTING ENTRIES DEBIT	CREDIT		TOTAL
A S S E T S				
CURRENT ASSETS				
Cash and cash equivalents				$ 26,686
Customer and other receivables - net		572	(b)	169,237
Accrued utility revenue				55,470
Materials and supplies				74,120
Fossil fuel				13,928
Deferred income taxes				69,688
Other current assets		91	(c)	41,140
Total current assets	--	663		450,269
INVESTMENTS AND OTHER ASSETS				
Real estate investments, net (cap interest)		8,950	(f)	398,527
Other assets		2,090,977	(a)	173,109
Total investments and other	--	2,099,927		571,636
UTILITY PLANT				
Electric plant in service and held for future us				6,803,211
Less accumulated depreciation and amortization				2,426,143
Total	--	--		4,377,068
Construction work in progress				226,935
Nuclear Fuel				51,137
Net Utility Plant	--	--		4,655,140
DEFERRED DEBITS				
Regulatory asset for income taxes				516,722
Rate synchronization deferral				414,082
Other deferred debits				381,440
Total deferred debits	--	--		1,312,244
TOTAL ASSETS	$ --	$ 2,100,590		$ 6,989,289

PINNACLE WEST CAPITAL CORPORATION
CONSOLIDATING BALANCE SHEET
December 31, 1996
(THOUSANDS OF DOLLARS)

	PWCC	APS	SUNCOR	ELDO
L I A B I L I T I E S A N D E Q U I T Y				
CURRENT LIABILITIES				
Accounts payable	$ 2,958	$ 174,394	$ 6,625	$ 118
Accrued taxes	(3,914)	86,327	--	
Accrued interest	208	39,115	326	
Dividend payable	--	--		
Short-term borrowings	--	--		
Commerical paper, net	--	16,900		
Current maturities of long-term debt	--	153,780	2,497	
Customer Deposits		32,137	2,085	
Other current liabilities	18,199	21,150	907	
Total current liabilities	17,451	523,803	12,440	118
LONG-TERM DEBT LESS CURRENT MATURITIES	250,000	2,029,482	92,631	
DEFERRED CREDITS AND OTHER				
Deferred income taxes	(54,930)	1,414,242		
Deferred investment tax credit	(13,344)	87,723		
Unamortized gain-sale of utility plant		86,939		
Other deferred credits	16,972	332,970	4,459	
Total deferred credits	(51,302)	1,921,874	4,459	--
COMMITMENTS AND CONTINGENCIES (NOTE)				
MINORITY INTERESTS:				
Non-Redeemable preferred stock of APS		165,673		
Redeemable preferred stock of APS		53,000		
Joint Ventures of SunCor			8,950	
COMMON STOCK EQUITY:				
Common stock	2,109,455	1,269,284	444,391	62,546
Accumulated deficit	(139,132)	460,106	(121,493)	(23,857)
Total	1,970,323	1,729,390	322,898	38,689
TOTAL LIABILITIES AND EQUITY	$ 2,186,472	$ 6,423,222	$ 441,378	$ 38,807

	ELIMINATIONS AND ADJUSTING ENTRIES DEBIT	CREDIT	TOTAL
L I A B I L I T I E S A N D E Q U I T Y			
CURRENT LIABILITIES			
Accounts payable			$ 184,095
Accrued taxes			82,413
Accrued interest			39,652
Dividend payable	-- (d)		--
Short-term borrowings			--
Commerical paper, net			16,900
Current maturities of long-term debt			156,277
Customer Deposits			34,222
Other current liabilities	3,197 (b),(c), (e)		37,056
Total current liabilities	3,197	--	550,615
LONG-TERM DEBT LESS CURRENT MATURITIES			2,372,113
DEFERRED CREDITS AND OTHER			
Deferred income taxes			1,359,312
Deferred investment tax credit			74,379
Unamortized gain-sale of utility plant			86,939
Other deferred credits		2,534 (e)	356,935
Total deferred credits	--	2,534	1,877,565
COMMITMENTS AND CONTINGENCIES (NOTE)			
MINORITY INTERESTS:			
Non-Redeemable preferred stock of APS			165,673
Redeemable preferred stock of APS			53,000
Joint Ventures of SunCor	8,950 (e)		--
COMMON STOCK EQUITY:			
Common stock	2,249,322 (a)		1,636,354
Accumulated deficit		158,345 (a)	333,969
Total	2,249,322	158,345	1,970,323
TOTAL LIABILITIES AND EQUITY	$ 2,261,469	$ 160,879	$ 6,989,289

PINNACLE WEST CAPITAL CORPORATION
CONSOLIDATING BALANCE SHEET
ELIMINATING AND ADJUSTING ENTRIES

(a)	Common stock	2,249,322	
	Notes payable - SunCor, El Dorado	--	
	Accumulated deficit	--	158,345
	Other investments		2,090,977
	Total	2,249,322	2,249,322

To eliminate PWCC investment in subsidiaries

	Common Stock	Earnings/ Dividends	Notes	Total
APS	1,742,385	(12,995)	--	1,729,390
SunCor	444,391	(121,493)	--	322,898
El Dorado	62,546	(23,857)	--	38,689
Total	2,249,322	(158,345)	--	2,090,977

(b)	Other current liabilities	572	
	Customer and other receivables - net		572

To eliminate intercompany receivable/payable

	A/R PWCC's Books	A/P SUB's Books
APS	130	130
SunCor	443	443
El Dorado	(1)	(1)
Total	572	572

(c)	Other current liabilities (PWCC)	91	
	Other current assets (APS)		91

To eliminate PWCC payable to APS

(d)	Dividends Payable (APS)	--	
	Customer and other receiv. (PNW)		--

To eliminate APS Dividend to PNW

(e)	Current Liabilities (PNW)	2,534	
	Deferred Credits (PNW)		2,534

Reclass deferred compensation

(f)	Scottsdale Mountain - Minority Interest	8,950	
	Real estate investments - net		8,950

To eliminate Minority Interest - SunCor Scottsdale Mountain

SUNCOR DEVELOPMENT COMPANY
CONSOLIDATING BALANCE SHEET
FOR THE MONTH ENDED DECEMBER 31, 1996

ACCOUNT DESCRIPTION	SUNCOR	LPSCO	SASI	SCTS MTN	PVGC	SHI	SCM
ASSETS:							
CURRENT ASSETS							
CASH AND SHORT TERM INVESTMENTS	$ 4,666,819	$ 345,533	$ 417,524	$ 1,509,499	$ 47,652	$ (14,235)	$ (352,503)
ACCOUNTS RECEIVABLE	356,927	84,647	141,936	327,513	28,180	83,181	49,263
INTERCOMPANY ACCOUNTS:							
SASI			368				
LPSCO	85,521						
SMLP	18,333						
KABUTO JV	--						
PVGC	--						
SCM/SHI I/C - 12901 & 12201	--					1,685,351	(1,685,351)
SCM/SHI I/C - 12902	--					(2,379,358)	2,379,358
SCM - SDC -12903	--						(4,663,344)
SHI - SDC - 12903 & 265	125,501					333,738	
WWOS	18,733						
GOLDEN HERITAGE	42,465						
HOMEBUILDING I/C INTEREST	135,646						
GOLDEN HERITAGE CASH ADVANCE	11,692,358						(11,692,358)
SUNRIDGE - DEVELOPMENT	60,698						
SUNRIDGE - GOLF	114,958						
SEDONA - DEVELOPMENT	44,281						
SEDONA - GOLF	(205,396)						
WIGWAM RESORT	377,474						
OUTER LIMITS (2000)	(58,140)						
COMMERCIAL PROJECT - GENERAL	5,051,459						
FIDDLESTICKS	3,685,231						
FUNTASTICKS	4,590,012						
HIDDEN HILLS	174,208						
RANCHO VIEJO	756,736						
INTEREST RECEIVABLE	132,659			117,857			
NOTES RECEIVABLE	3,145,422	4,746		2,603,250			
INVENTORIES	--				72,984		
PREPAID EXPENSES	--	14,564			57,875		
HOME INVENTORY	52,919					2,442,969	16,518,852
TOTAL CURRENT ASSETS	35,064,824	449,490	559,828	4,558,119	206,691	2,151,646	553,917

ACCOUNT DESCRIPTION	WWOS	GH HOMES	KABUTO JV	COMMERCIAL	HIDDEN HILLS	RANCHO VIEJO	ELIMINATIONS REF	ELIMINATIONS DEBIT	ELIMINATIONS REF	ELIMINATIONS CREDIT
ASSETS:										
CURRENT ASSETS										
CASH AND SHORT TERM INVESTMENTS	$ 93,801		$ 250	$ (494,705)		$ 5,000				
ACCOUNTS RECEIVABLE	(25,497)			38,451						
INTERCOMPANY ACCOUNTS:										
SASI							P	172		
LPSCO									M	85,521
SMLP									O	18,333
KABUTO JV										
PVGC										
SCM/SHI I/C - 12901 & 12201							AB	6,603,859	AB	6,603,859
SCM/SHI I/C - 12902							C	2,379,358	C	2,379,358
SCM - SDC -12903							D	4,663,344		
SHI - SDC - 12903 & 265							D	1,432,265	D	1,891,504
WWOS									U	18,733
GOLDEN HERITAGE									G	42,465
HOMEBUILDING I/C INTEREST									F	135,646
GOLDEN HERITAGE CASH ADVANCE							E	11,692,358	E	11,692,358
SUNRIDGE - DEVELOPMENT										
SUNRIDGE - GOLF										
SEDONA - DEVELOPMENT										
SEDONA - GOLF										
WIGWAM RESORT										
OUTER LIMITS (2000)							X	58,140		
COMMERCIAL PROJECT - GENERAL									X	5,051,459
FIDDLESTICKS									X	3,685,231
FUNTASTICKS									X	4,590,012
HIDDEN HILLS									Z	174,208
RANCHO VIEJO									AA	756,736
INTEREST RECEIVABLE									T	72,611
NOTES RECEIVABLE	8,041									
INVENTORIES				21,609						
PREPAID EXPENSES				44,358						
HOME INVENTORY									J	1,075,417
TOTAL CURRENT ASSETS	76,345	--	250	(390,287)	--	5,000		26,829,496		38,273,451

ACCOUNT DESCRIPTION	CONSOLIDATED
ASSETS:	
CURRENT ASSETS	
CASH AND SHORT TERM INVESTMENTS	$ 6,224,635
ACCOUNTS RECEIVABLE	1,084,601
INTERCOMPANY ACCOUNTS:	
SASI	540
LPSCO	--
SMLP	--
KABUTO JV	--
PVGC	--
SCM/SHI I/C - 12901 & 12201	--
SCM/SHI I/C - 12902	--
SCM - SDC -12903	--
SHI - SDC - 12903 & 265	--
WWOS	--
GOLDEN HERITAGE	--
HOMEBUILDING I/C INTEREST	--
GOLDEN HERITAGE CASH ADVANCE	60,698
SUNRIDGE - DEVELOPMENT	114,958
SUNRIDGE - GOLF	44,281
SEDONA - DEVELOPMENT	(205,396)
SEDONA - GOLF	377,474
WIGWAM RESORT	--
OUTER LIMITS (2000)	--
COMMERCIAL PROJECT - GENERAL	--
FIDDLESTICKS	--
FUNTASTICKS	--
HIDDEN HILLS	--
RANCHO VIEJO	--
	--
INTEREST RECEIVABLE	177,905
NOTES RECEIVABLE	5,761,459
INVENTORIES	94,593
PREPAID EXPENSES	116,797
HOME INVENTORY	17,939,323
TOTAL CURRENT ASSETS	31,791,868

ACCOUNT DESCRIPTION	SUNCOR	LPSCO	SASI	SCTS MTN	PVGC	SHI	SCM
LONG-TERM ASSETS							
DEVELOPMENT PROJECTS							
HIDDEN HILLS							
RANCHO VIEJO							
PALM VALLEY	202,486,457						
LITCHFIELD GREENS	2,987,026						
KABUTO JV	--						
SCOTTSDALE MTN	--			10,637,107			
MARKETPLACE - CENTERPOINT	21,464,829						
TATUM RANCH	40,840,941						
TALAVI	8,494,198						
RESTORATION PLACE - TOWNE CNTR	(11,827)						
WIGWAM OUTLET STORES	--						
GOLDEN HERITAGE LAND	--						955,487
EQUITY INVESTMENTS:							
EQUITY IN TEMPE MKTPL JV	4,657,017						
EQUITY IN CTRPT ASSOC-JV	23,216,298						
INVESTMENT IN BILTMORE ESTATES	464,583						
INVEST IN PV APARTMENTS	817,002						
INVESTMENT IN SUNRIDGE CANYON	11,201,128						
INVESTMENT IN SEDONA GOLF	6,116,340						
INVESTMENT IN PLUMCOR OFFICE JV	2,569,397						
CONSOLIDATED ELIMINATING ENTITIES:							
INVEST IN KABUTO JV	5,769,120						
INVESTMENT IN WIGWAM OUTLET	5,501,073						
INVEST IN SCOTTS MTN LTD PART	11,106,848						
INVEST IN SUNCOR HOMES:							
SUNCOR HOMES EARNINGS	223,493						
GOLDEN HERITAGE EARNINGS	(1,794,677)						
INVEST IN GOLDEN HERITAGE HOMES	26,501						
INVESTMENT IN LPSCO	8,277,474						
INVESTMENT IN SASI	400,109						
INVESTMENT IN PALM VALLEY GOLF	6,553,930						
INVESTMENT IN OUTER LIMITS	1,668,979						
INVESTMENT IN FIDDLESTICKS	(31,249)						
INVESTMENT IN FUNTASTICKS	(43,535)						
INVESTMENT IN COMM OPS	5,351						
INVESTMENT IN PV PAVILIONS	(100)						
INVESTMENT IN PV CROSSING	(31,673)						
INVESTMENT IN AUTOPLEX	(286)						
INVESTMENT IN TALAVI	(2,841)						
INVESTMENT IN RANCHO VIEJO	(13,893)						
COMMERCIAL PROPERTIES	2,480,405				5,598,637		
LONG-TERM NOTES RECEIVABLE	1,229,007			2,901,096			
SDC PHASE I LAND NOTE TO WWOS	1,611,156						
SDC PAYOFF OF WWOS RLC	10,000,000						
SDC LOAN TO LPSCO	300,000						
PALM VALLEY GOLF INTERCOMPANY	(4,021,827)				4,021,827		
BUILDING, EQUIPMENT AND OTHER (NET)	701,119	--	36,696	1,127	45,773	841,862	104,245
DEFERRED ASSETS	3,314,819	576,836		--	257,173		
WATER, SEWER UTILITY PROP (NET)	--	8,609,113					
CONTRIBUTED PROPERTY	--	1,059,926				8,630	153,175
DEPOSITS							
TOTAL LONG-TERM ASSETS	378,532,692	10,245,875	36,696	13,539,330	9,923,410	850,492	1,212,907
TOTAL ASSETS	$413,597,516	$10,695,365	$ 596,524	$18,097,449	$10,130,101	$3,002,138	$1,766,824

ACCOUNT DESCRIPTION	WWOS	GH HOMES	KABUTO JV	COMMERCIAL	HIDDEN HILLS	RANCHO VIEJO	ELIMINATIONS REF	ELIMINATIONS DEBIT	ELIMINATIONS REF	ELIMINATIONS CREDIT
LONG-TERM ASSETS										
DEVELOPMENT PROJECTS										
HIDDEN HILLS					174,208					
RANCHO VIEJO						737,843				
PALM VALLEY				5,286,144						
LITCHFIELD GREENS			12,574,976							
KABUTO JV									V	2,956,571
SCOTTSDALE MTN									N	83,503
MARKETPLACE - CENTERPOINT				504,883						
TATUM RANCH										
TALAVI				32,623						
RESTORATION PLACE - TOWNE CNTR										
WIGWAM OUTLET STORES	18,241,943						S	451,398	S	1,559,870
GOLDEN HERITAGE LAND										
EQUITY INVESTMENTS:										
EQUITY IN TEMPE MKTPL JV										
EQUITY IN CTRPT ASSOC-JV										
INVESTMENT IN BILTMORE ESTATES										
INVEST IN PV APARTMENTS										
INVESTMENT IN SUNRIDGE CANYON										
INVESTMENT IN SEDONA GOLF										
INVESTMENT IN PLUMCOR OFFICE JV										
CONSOLIDATED ELIMINATING ENTITIES:										
INVEST IN KABUTO JV									V	5,769,120
INVESTMENT IN WIGWAM OUTLET									S	5,501,073
INVEST IN SCOTTS MTN LTD PART									N	11,106,848
INVEST IN SUNCOR HOMES:									H	223,493
SUNCOR HOMES EARNINGS										
GOLDEN HERITAGE EARNINGS							H	1,794,677		
INVEST IN GOLDEN HERITAGE HOMES										
INVESTMENT IN LPSCO									K	8,277,474
INVESTMENT IN SASI									P	400,109
INVESTMENT IN PALM VALLEY GOLF									Q	6,553,930
INVESTMENT IN OUTER LIMITS									Y	1,668,979
INVESTMENT IN FIDDLESTICKS							Y	31,249		
INVESTMENT IN FUNTASTICKS							Y	43,535		
INVESTMENT IN COMM OPS									Y	5,351
INVESTMENT IN PV PAVILIONS							Y	100		
INVESTMENT IN PV CROSSING							Y	31,673		
INVESTMENT IN AUTOPLEX							Y	286		
INVESTMENT IN TALAVI							Y	2,841		
INVESTMENT IN RANCHO VIEJO							BB	13,893		
COMMERCIAL PROPERTIES				10,733,633						
LONG-TERM NOTES RECEIVABLE										
SDC PHASE I LAND NOTE TO WWOS									T	1,611,156
SDC PAYOFF OF WWOS RLC									T	10,000,000
SDC LOAN TO LPSCO									L	300,000
PALM VALLEY GOLF INTERCOMPANY							R	4,021,827	R	4,021,827
BUILDING, EQUIPMENT AND OTHER (NET)										
DEFERRED ASSETS	523,145			72,193						
WATER, SEWER UTILITY PROP (NET)										
CONTRIBUTED PROPERTY										
DEPOSITS										
TOTAL LONG-TERM ASSETS	18,765,088	--	12,574,976	16,629,476	174,208	737,843		6,391,479		60,039,304
TOTAL ASSETS	$18,841,433	$ --	$12,575,226	$16,239,189	$174,208	$742,843		$33,220,975		$98,312,755

ACCOUNT DESCRIPTION	CONSOLIDATED
LONG-TERM ASSETS	
DEVELOPMENT PROJECTS	
HIDDEN HILLS	174,208
RANCHO VIEJO	737,843
PALM VALLEY	207,772,601
LITCHFIELD GREENS	2,987,601
KABUTO JV	9,618,405
SCOTTSDALE MTN	10,553,604
MARKETPLACE - CENTERPOINT	21,969,712
TATUM RANCH	40,840,941
TALAVI	8,526,941
RESTORATION PLACE - TOWNE CNTR	(11,827)
WIGWAM OUTLET STORES	17,133,471
GOLDEN HERITAGE LAND	955,487
EQUITY INVESTMENTS:	
EQUITY IN TEMPE MKTPL JV	4,657,017
EQUITY IN CTRPT ASSOC-JV	23,216,298
INVESTMENT IN BILTMORE ESTATES	464,583
INVEST IN PV APARTMENTS	817,002
INVESTMENT IN SUNRIDGE CANYON	11,201,128
INVESTMENT IN SEDONA GOLF	6,116,340
INVESTMENT IN PLUMCOR OFFICE JV	2,569,397
CONSOLIDATED ELIMINATING ENTITIES:	
INVEST IN KABUTO JV	--
INVESTMENT IN WIGWAM OUTLET	--
INVEST IN SCOTTS MTN LTD PART	--
INVEST IN SUNCOR HOMES:	
SUNCOR HOMES EARNINGS	--
GOLDEN HERITAGE EARNINGS	--
INVEST IN GOLDEN HERITAGE HOMES	26,501
INVESTMENT IN LPSCO	--
INVESTMENT IN SASI	--
INVESTMENT IN PALM VALLEY GOLF	--
INVESTMENT IN OUTER LIMITS	--
INVESTMENT IN FIDDLESTICKS	--
INVESTMENT IN FUNTASTICKS	--
INVESTMENT IN COMM OPS	--
INVESTMENT IN PV PAVILIONS	--
INVESTMENT IN PV CROSSING	--
INVESTMENT IN AUTOPLEX	--
INVESTMENT IN TALAVI	--
INVESTMENT IN RANCHO VIEJO	--
COMMERCIAL PROPERTIES	18,812,675
LONG-TERM NOTES RECEIVABLE	4,130,103
SDC PHASE I LAND NOTE TO WWOS	--
SDC PAYOFF OF WWOS RLC	--
SDC LOAN TO LPSCO	--
PALM VALLEY GOLF INTERCOMPANY	--
BUILDING, EQUIPMENT AND OTHER (NET)	1,730,822
DEFERRED ASSETS	4,744,166
WATER, SEWER UTILITY PROP (NET)	8,609,113
CONTRIBUTED PROPERTY	1,059,926
DEPOSITS	161,805
TOTAL LONG-TERM ASSETS	409,575,168
TOTAL ASSETS	$ 441,367,036

ACCOUNT DESCRIPTION	SUNCOR	LPSCO	SASI	SCTS MTN	PVGC	SHI	SCM
LIABILITIES:							
CURRENT LIABILITIES							
A/P & RETENTION	$ 1,054,550	$ 389,898	$ 40,744	$ 111,922	$ 40,654	$ 138,251	$ 582,108
ACCRUED LIABILITIES	1,806,502	34,416	155,843	336,426	54,334	33,559	
INTERCOMPANY ACCOUNTS:							
LPSCO - SDC		117,889					
SMLP - SDC				18,333			
PVGC							
SCM-SDC INTERCOMPANY	(4,204,105)						
SHI-SDC INTERCOMPANY	129,234,240					25,158	
SCM EARNINGS	(395,624)						
WWOS							
KABUTO JV							
OUTER LIMITS - SDC							
COMMERCIAL OPERATIONS - GENERAL							
FIDDLESTICKS							
FUNTASTICKS							
HIDDEN HILLS							
RANCHO VIEJO							
INTEREST PAYABLE	325,581					17,307	135,646
S/T NOTES PAYABLE OTHER							
TATUM RANCH MONK NOTE	78,027						
SMLP	--			936,893			
GOLDEN HERITAGE (PEW)							
TEXTRON LOAN							
DEFERRED PROFIT	1,237,716			387,692			
PWCC INTERCO PAYABLE	337,995						
CUSTOMER DEPOSITS	117,067					1,314,797	653,446
ACCRUED TAXES		18,714					
TOTAL CURRENT LIABILITIES	357,709	560,917	196,587	1,791,266	94,988	1,529,072	1,371,200
LONG-TERM LIABILITIES							
LONG-TERM NOTES PAYABLE							
TATUM RANCH MONK NOTE	156,053						
WWOS OWES SCD PH I LAND NOTE							
WWOS RLC PAYOFF BY SDC							
CORPORATE TERM NOTE	45,000,000						
CORPORATE RLC	42,431,700						
LPSCO OWES SDC		300,000					
GOLDEN HERITAGE (PEW)						3,044,250	
TEXTRON LOAN					3,481,183		
OTHER ACCRUED LIABILITIES	2,754,358						
DEFERRED TAXES		238,404					
LONG-TERM ADVANCE-IN-AID		--					
LONG-TERM METER DEPOSITS		405,425					
CONTRIB PROPERTY AIA		1,059,925					
TOTAL L/T LIABILITIES	90,342,111	2,003,754	--	--	3,481,183	3,044,250	--
TOTAL LIABILITIES	90,699,820	2,564,671	196,587	1,791,266	3,576,171	4,573,322	1,371,200
MINORITY INTEREST							
EQUITY:							

ACCOUNT DESCRIPTION	SUNCOR	LPSCO	SASI	SCTS MTN	PVGC	SHI	SCM
SDC COMMON STOCK	1,022,000						
SDC ADDITIONAL PAID IN CAPITAL	443,368,522						
SDC EARNED SURPLUS-BEGINNING	(125,646,609)						
SDC EARNED SURPLUS-CURRENT	4,153,783						
SUBSIDIARY EARNINGS-CURRENT		19,237	4,468	7,168,410	100,993	(1,359,913)	16,338
SUBSIDIARY EQUITY:							
LPSCO		8,111,457					
SASI			395,469				
SMLP				9,137,773			
PVGC					6,452,937		
SCM							379,286
SHOMES						(211,271)	
WWOS							
GOLDEN HERITAGE							
KABUTO JV							
OUTER LIMITS							
TOTAL EQUITY	322,897,696	8,130,694	399,937	16,306,183	6,553,930	(1,571,184)	395,624
TOTAL LIABILITIES AND EQUITY	$413,597,516	$10,695,365	$ 596,524	$ 18,097,449	$ 10,130,101	$3,002,138	$ 1,766,824

ACCOUNT DESCRIPTION	WWOS	GH HOMES	KABUTO JV	COMMERCIAL	HIDDEN HILLS	RANCHO VIEJO	ELIMINATIONS REF	ELIMINATIONS DEBIT	ELIMINATIONS REF	ELIMINATIONS CREDIT
LIABILITIES:										
CURRENT LIABILITIES										
A/P & RETENTION	$ --			$ 1,204,911						
ACCRUED LIABILITIES	529,388		15,000	63,963						
INTERCOMPANY ACCOUNTS:										
LPSCO - SDC							M	85,521		
SMLP - SDC							O	18,333		
PVGC									D	4,204,105
SCM-SDC INTERCOMPANY							G	25,158		
SHI-SDC INTERCOMPANY	129,234,240								I	395,624
SCM EARNINGS							U	18,733		
WWOS	18,733							--		
KABUTO JV				(58,140)					X	58,140
OUTER LIMITS - SDC				5,051,459			X	5,051,459		
COMMERCIAL OPERATIONS - GENERAL				3,685,231			X	3,685,231		
FIDDLESTICKS				4,590,012			X	4,590,012		
FUNTASTICKS					174,208		Z	174,208		
HIDDEN HILLS						756,736	AA	756,736		
RANCHO VIEJO										
INTEREST PAYABLE	72,611						FGT	225,564		
S/T NOTES PAYABLE OTHER										
TATUM RANCH MONK NOTE										
SMLP									**	1,420,000
GOLDEN HERITAGE (PEW)									*	61,892
TEXTRON LOAN										
DEFERRED PROFIT							J	1,075,417		
PWCC INTERCO PAYABLE										
CUSTOMER DEPOSITS										
ACCRUED TAXES										
TOTAL CURRENT LIABILITIES	620,732	--	15,000	14,537,436	174,208	756,736		15,706,372		6,139,761
LONG-TERM LIABILITIES										
LONG-TERM NOTES PAYABLE										
TATUM RANCH MONK NOTE										
WWOS OWES SCD PH I LAND NOTE	1,611,156						T	1,611,156		
WWOS RLC PAYOFF BY SDC	10,000,000						T	10,000,000		
CORPORATE TERM NOTE										
CORPORATE RLC										
LPSCO OWES SDC							L	300,000		
GOLDEN HERITAGE (PEW)							**	1,420,000		
TEXTRON LOAN							*	61,892		
OTHER ACCRUED LIABILITIES				137,107						
DEFERRED TAXES								146,780		
LONG-TERM ADVANCE-IN-AID										
LONG-TERM METER DEPOSITS										
CONTRIB PROPERTY AIA										
TOTAL L/T LIABILITIES	11,611,156	--	--	137,107	--	--		13,539,828		--
TOTAL LIABILITIES	12,231,888	--	15,000	14,674,543	174,208	756,736		29,246,200		6,139,761
MINORITY INTEREST									NV	8,950,367
EQUITY:										

ACCOUNT DESCRIPTION	WWOS	GH HOMES	KABUTO JV	COMMERCIAL	HIDDEN HILLS	RANCHO VIEJO	ELIMINATIONS REF	ELIMINATIONS DEBIT	ELIMINATIONS REF	ELIMINATIONS CREDIT
SDC COMMON STOCK										
SDC ADDITIONAL PAID IN CAPITAL										
SDC EARNED SURPLUS-BEGINNING										
SDC EARNED SURPLUS-CURRENT										
SUBSIDIARY EARNINGS-CURRENT	(1,101,590)		--	(257,869)		(13,893)	IKNPQ	7,309,446	HSY(BB)	2,733,265
SUBSIDIARY EQUITY:										
LPSCO							K	8,111,457		
SASI							P	395,469		
SMLP							N	9,137,773		
PVGC							Q	6,452,937		
SCM							I	379,286		
SHOMES									H	211,271
WWOS	7,711,135						S	7,711,135		
GOLDEN HERITAGE										
KABUTO JV			12,560,226				V	12,560,226		
OUTER LIMITS				1,822,515			Y	1,822,515		
TOTAL EQUITY	6,609,545	--	12,560,226	1,564,646	--	(13,893)		53,880,244		2,944,536
TOTAL LIABILITIES AND EQUITY	$18,841,433	$ --	$12,575,226	$16,239,189	$174,208	$742,843		$83,126,444		$18,034,664

ACCOUNT DESCRIPTION	CONSOLIDATED
LIABILITIES:	
CURRENT LIABILITIES	
A/P & RETENTION	$ 3,563,038
ACCRUED LIABILITIES	3,029,431
INTERCOMPANY ACCOUNTS:	
LPSCO - SDC	32,368
SMLP - SDC	--
PVGC	--
SCM-SDC INTERCOMPANY	--
SHI-SDC INTERCOMPANY 129,234,240	--
SCM EARNINGS	--
WWOS	--
KABUTO JV	--
OUTER LIMITS - SDC	--
COMMERCIAL OPERATIONS - GENERAL	--
FIDDLESTICKS	--
FUNTASTICKS	--
HIDDEN HILLS	--
RANCHO VIEJO	--
INTEREST PAYABLE	325,581
S/T NOTES PAYABLE OTHER	
TATUM RANCH MONK NOTE	78,027
SMLP	936,893
GOLDEN HERITAGE (PEW)	1,420,000
TEXTRON LOAN	61,892
DEFERRED PROFIT	549,991
PWCC INTERCO PAYABLE	337,995
CUSTOMER DEPOSITS	2,085,310
ACCRUED TAXES	18,714
TOTAL CURRENT LIABILITIES	12,439,240
LONG-TERM LIABILITIES	
LONG-TERM NOTES PAYABLE	--
TATUM RANCH MONK NOTE	156,053
WWOS OWES SCD PH I LAND NOTE	--
WWOS RLC PAYOFF BY SDC	--
CORPORATE TERM NOTE	45,000,000
CORPORATE RLC	42,431,700
LPSCO OWES SDC	--
GOLDEN HERITAGE (PEW)	1,624,250
TEXTRON LOAN	3,419,291
OTHER ACCRUED LIABILITIES	2,891,465
DEFERRED TAXES	91,624
LONG-TERM ADVANCE-IN-AID	--
LONG-TERM METER DEPOSITS	405,425
CONTRIB PROPERTY AIA	1,059,925
TOTAL L/T LIABILITIES	97,079,733
TOTAL LIABILITIES	109,518,973
MINORITY INTEREST	8,950,367
EQUITY:	

SDC COMMON STOCK	1,022,000
SDC ADDITIONAL PAID IN CAPITAL	443,368,522
SDC EARNED SURPLUS-BEGINNING	(125,646,609)
SDC EARNED SURPLUS-CURRENT	4,153,783
SUBSIDIARY EARNINGS-CURRENT	--
SUBSIDIARY EQUITY:	
LPSCO	--
SASI	--
SMLP	--
PVGC	--
SCM	--
SHOMES	--
WWOS	--
GOLDEN HERITAGE	--
KABUTO JV	--
OUTER LIMITS	--
TOTAL EQUITY	322,897,696
TOTAL LIABILITIES AND EQUITY	$ 441,367,036

SUNCOR DEVELOPMENT COMPANY
CONSOLIDATING INCOME STATEMENT
FOR THE YEAR ENDING DECEMBER 31, 1996

ACCOUNT DESCRIPTION	SUNCOR	LPSCO	SCTS MTN
REVENUES:			
SALE OF ASSETS	$ 30,633	$ --	$ --
DEFERRED PROFIT	(163,914)	--	91,639
LAND SALES	30,253,994	--	13,194,485
HOME SALES	--	--	--
COMMERCIAL PROPERTIES	4,660,516	--	--
UTILITY SALES	--	1,448,257	--
MANAGEMENT FEES	1,329,474	--	--
TOTAL OPERATING REVENUES	36,110,703	1,448,257	13,286,124
OPERATING EXPENSES			
COST OF ASSETS SOLD	49,726	--	--
COST OF LAND SOLD	23,696,669	--	5,590,797
COST OF HOMES SOLD	(1,685,689)	--	--
LAND PROJECT COSTS	2,148,254	--	346,884
COMMERCIAL PROPERTIES	3,588,341	--	--
GENERAL & ADMINISTRATIVE	8,273,501	--	377,161
UTILITY EXPENSE	--	1,288,886	--
RESORT OPERATIONS	69,436	--	--
DEPRECIATION & AMORTIZATION	668,010	233,190	563
TOTAL OPERATING EXPENSES	36,808,248	1,522,076	6,315,405
NET OPERATING INCOME	(697,545)	(73,819)	6,970,719
OTHER INCOME AND GAINS:			
EQUITY IN JOINT VENTURES	3,399,538	--	--
INTEREST INCOME	399,334	6,716	212,962
TOTAL OTHER INCOME AND GAINS	3,798,872	6,716	212,962
INTEREST EXPENSE			
INTEREST EXPENSE	4,332,252	26,872	330,309
LESS: CAPITALIZED INTEREST	(2,865,470)	--	(315,036)
TOTAL INTEREST EXPENSE	1,466,782	26,872	15,273
NET INCOME BEFORE MINORITY INTEREST	1,634,545	(93,975)	7,168,408
MINORITY INTEREST	2,216,127	--	--
NET INCOME/(LOSS)	$ (581,582)	$ (93,975)	$ 7,168,408

ACCOUNT DESCRIPTION	PVGC	SCM	S HOMES
REVENUES:			
SALE OF ASSETS	$ --	$ --	$ --
DEFERRED PROFIT	--	--	--
LAND SALES	--	--	--
HOME SALES	--	18,566,949	45,860,575
COMMERCIAL PROPERTIES	2,137,042	--	--
UTILITY SALES	--	--	--
MANAGEMENT FEES	--	--	--
TOTAL OPERATING REVENUES	2,137,042	18,566,949	45,860,575
OPERATING EXPENSES			
COST OF ASSETS SOLD	--	--	--
COST OF LAND SOLD	--	--	--
COST OF HOMES SOLD	--	18,136,772	42,738,830
LAND PROJECT COSTS	--	--	--
COMMERCIAL PROPERTIES	1,753,380	--	--
GENERAL & ADMINISTRATIVE	--	409,754	4,336,226
UTILITY EXPENSE	--	--	--
RESORT OPERATIONS	--	--	--
DEPRECIATION & AMORTIZATION	162,495	4,084	162,030
TOTAL OPERATING EXPENSES	1,915,875	18,550,610	47,237,086
NET OPERATING INCOME	221,167	16,339	(1,376,511)
OTHER INCOME AND GAINS:			
EQUITY IN JOINT VENTURES	--	--	--
INTEREST INCOME	--	--	16,599
TOTAL OTHER INCOME AND GAINS	--	--	16,599
INTEREST EXPENSE			
INTEREST EXPENSE	120,175	--	--
LESS: CAPITALIZED INTEREST	--	--	--
TOTAL INTEREST EXPENSE	120,175	--	--
NET INCOME BEFORE MINORITY INTEREST	100,992	16,339	(1,359,912)
MINORITY INTEREST	--	--	--
NET INCOME/(LOSS)	$ 100,992	$ 16,339	$ (1,359,912)

ACCOUNT DESCRIPTION	WWOS	RANCHO VIEJO	ELIMINATING ENTRIES	
REVENUES:				
SALE OF ASSETS	$ --	$ --	$ --	
DEFERRED PROFIT	--	--	--	
LAND SALES	--	--	--	
HOME SALES	--	--	(18,566,949)	A
COMMERCIAL PROPERTIES	2,005,457	--	--	
UTILITY SALES	--	--	--	
MANAGEMENT FEES	--	--	--	
TOTAL OPERATING REVENUES	2,005,457	--	(18,566,949)	
OPERATING EXPENSES				
COST OF ASSETS SOLD	--	--	--	
COST OF LAND SOLD	--	--	--	
COST OF HOMES SOLD	--	--	(18,566,949)	A
LAND PROJECT COSTS	--	--	--	
COMMERCIAL PROPERTIES	1,082,120	--	--	
GENERAL & ADMINISTRATIVE	--	13,894	--	
UTILITY EXPENSE	--	--	--	
RESORT OPERATIONS	--	--	--	
DEPRECIATION & AMORTIZATION	850,975	--	--	
TOTAL OPERATING EXPENSES	1,933,095	13,894	(18,566,949)	
NET OPERATING INCOME	72,362	(13,894)	--	
OTHER INCOME AND GAINS:				
EQUITY IN JOINT VENTURES	--	--	--	
INTEREST INCOME	5,622	--	--	
TOTAL OTHER INCOME AND GAINS	5,622	--	--	
INTEREST EXPENSE				
INTEREST EXPENSE	1,327,300	--	--	
LESS: CAPITALIZED INTEREST	(166,760)	--	--	
TOTAL INTEREST EXPENSE	1,160,540	--	--	
NET INCOME BEFORE MINORITY INTEREST	(1,082,556)	(13,894)	--	
MINORITY INTEREST	--	--	--	
NET INCOME/(LOSS)	$ (1,082,556)	$ (13,894)	$ --	

ACCOUNT DESCRIPTION	CONSOLIDATED INCOME
REVENUES:	
SALE OF ASSETS	$ 30,633
DEFERRED PROFIT	(72,275)
LAND SALES	43,448,479
HOME SALES	45,860,575
COMMERCIAL PROPERTIES	8,803,015
UTILITY SALES	1,448,257
MANAGEMENT FEES	1,329,474
TOTAL OPERATING REVENUES	100,848,158
OPERATING EXPENSES	
COST OF ASSETS SOLD	49,726
COST OF LAND SOLD	29,287,466
COST OF HOMES SOLD	40,622,964
LAND PROJECT COSTS	2,495,138
COMMERCIAL PROPERTIES	6,423,841
GENERAL & ADMINISTRATIVE	13,563,521
UTILITY EXPENSE	1,135,901
RESORT OPERATIONS	69,436
DEPRECIATION & AMORTIZATION	2,081,347
TOTAL OPERATING EXPENSES	95,729,340
NET OPERATING INCOME	5,118,818
OTHER INCOME AND GAINS:	
EQUITY IN JOINT VENTURES	3,399,538
INTEREST INCOME	641,233
TOTAL OTHER INCOME AND GAINS	4,040,771
INTEREST EXPENSE	
INTEREST EXPENSE	6,136,908
LESS: CAPITALIZED INTEREST	(3,347,266)
TOTAL INTEREST EXPENSE	2,789,642
NET INCOME BEFORE MINORITY INTEREST	6,369,947
MINORITY INTEREST	2,216,127
NET INCOME/(LOSS)	$ 4,153,820

A. HOME SALES		18,566,949	
	COST OF HOME SALES		18,136,772
	COST OF HOME SALES (SCM MARGIN)		430,177

ELIMINATE INTERCOMPANY SALES AND PROFITS BETWEEN SCM AND SUNCOR HOMES

SUNCOR DEVELOPMENT COMPANY
CONSOLIDATING BALANCE SHEET
DECEMBER 1996 ELIMINATING ENTRIES

		DEBIT	CREDIT
K.	LPSCO EQUITY	8,111,457	
	EARNED SURPLUS - CURRENT	19,237	
	INVESTMENT IN LPSCO		8,277,474
	DEFERRED TAXES	146,780	
	ELIMINATE SDC INVESTMENT IN LPSCO		
L	LONG-TERM NOTES PAYABLE	300,000	
	LONG-TERM NOTES RECEIVABLE		300,000
	ELIMINATE LPSCO INTERCOMPANY NOTE WITH SDC		
M	ACCOUNTS PAYABLE	85,521	
	ACCOUNTS RECEIVABLE		85,521
	ELIMINATE LPSCO INTERCOMPANY A/R WITH SDC		
N	SMLP EQUITY	9,137,773	
	EARNED SURPLUS - CURRENT	7,168,410	
	MINORITY INTEREST - PRIOR YEAR		2,606,888
	MINORITY INTEREST - CURRENT YEAR		2,508,944
	SMLP LAND		83,503
	INVESTMENT IN SMLP		11,106,848
	ELIMINATE SDC INVESTMENT IN SMLP		
O	ACCOUNTS PAYABLE	18,333	
	ACCOUNTS RECEIVABLE		18,333
	ELIMINATE SMLP INTERCOMPANY A/R WITH SDC		
P	SASI EQUITY	395,469	
	EARNED SURPLUS - CURRENT	4,468	
	ACCOUNTS PAYABLE	172	
	INVESTMENT IN SASI		400,109
	ELIMINATE SDC INVESTMENT IN SASI		
Q	EARNED SURPLUS - CURRENT	100,993	
	PALM VALLEY EQUITY	6,452,937	
	INVESTMENT IN PV GOLF CLUB		6,553,930
	ELIMINATE SDC INVESTMENT IN PALM VALLEY GOLF		
R	ACCOUNTS PAYABLE	4,021,827	
	ACCOUNTS RECEIVABLE		4,021,827
	ELIMINATE PVGC INTERCOMPANY A/R WITH SDC		
S	WWOS EQUITY	7,711,135	
	1994 CAPITALIZED INTEREST	344,558	
	DEVELOPMENT FEES	106,840	
	EARNED SURPLUS - CURRENT		1,101,590
	INVESTMENT IN WWOS		5,501,073
	BASIS DIFFERENTIAL IN LAND PH1		854,972
	BASIS DIFFERENTIAL IN BLDG		156,750
	BASIS DIFFERENTIAL IN LAND PH2		548,148
	ELIMINATE SDC INVESTMENT IN WIGWAM OUTLET STORES		
T	INTEREST PAYABLE	72,611	

	INTEREST RECEIVABLE		72,611
	NOTES PAYABLE	1,611,156	
	NOTES RECEIVABLE		1,611,156
	NOTES PAYABLE	10,000,000	
	NOTES RECEIVABLE		10,000,000
	ELIMINATE WWOS INTERCOMPANY NOTES AND INTEREST WITH SDC		
U	ACCOUNTS PAYABLE	18,733	
	ACCOUNTS RECEIVABLE		18,733
	ELIMINATE WWOS INTERCOMPANY A/R WITH SDC		
V	KABUTO JV EQUITY	12,560,226	
	MINORITY INTEREST		3,834,535
	INVESTMENT IN KABUTO JV		5,769,120
	KABUTO JV LAND		2,956,571
	ELIMINATE SDC INVESTMENT IN KABUTO JV		
W	ACCOUNTS PAYABLE	--	
	ACCOUNTS RECEIVABLE		--
	ELIMINATE KABUTO JV INTERCOMPANY A/R WITH SDC		
X	COMMERCIAL OPERATIONS - GENERAL A/P	5,051,459	
	COMMERCIAL OPERATIONS - OUTER LIMITS A/P		58,140
	COMMERCIAL OPERATIONS - FIDDLESTICKS A/P	3,685,231	
	COMMERCIAL OPERATIONS - FUNTASTICKS A/P	4,590,012	
	SUNCOR COMMERCIAL OPS - GENERAL A/R		5,051,459
	SUNCOR COMMERCIAL OPS - OUTER LIMITS A/R	58,140	
	SUNCOR COMMERCIAL OPS - FIDDLESTICKS A/R		3,685,231
	SUNCOR COMMERCIAL OPS - FUNTASTICKS A/R		4,590,012
	ELIMINATE COMMERCIAL OPERATIONS INTERCOMPANY A/R WITH SDC		
Y	COMMERCIAL OPERATIONS EQUITY	1,822,515	
	EARNED SURPLUS - CURRENT		257,869
	INVESTMENT IN OUTER LIMITS		1,668,979
	INVESTMENT IN FIDDLESTICKS	31,249	
	INVESTMENT IN FUNTASTICKS	43,535	
	INVESTMENT IN PV PAVILLIONS	100	
	INVESTMENT IN PV CROSSING	31,673	
	INVESTMENT IN COMM OPS		5,351
	INVESTMENT IN AUTOPLEX	286	
	INVESTMENT IN TALAVI	2,841	
	ELIMINATE SDC INVESTMENT IN COMMERCIAL OPERATIONS		
Z	ACCOUNTS PAYABLE	174,208	
	ACCOUNTS RECEIVABLE		174,208
	ELIMINATE HIDDEN HILLS INTERCOMPANY A/R WITH SDC		
AA	ACCOUNTS PAYABLE	756,736	
	ACCOUNTS RECEIVABLE		756,736
	ELIMINATE RANCO VIEJO INTERCOMPANY A/R WITH SDC		
BB	INVESTMENT IN RANCHO VIEJO	13,893	
	EARNED SURPLUS - CURRENT		13,893
	ELIMINATE SDC INVESTMENT IN RANCHO VIEJO JV		
		84,636,621	84,636,621

SUNCOR DEVELOPMENT COMPANY
CONSOLIDATING BALANCE SHEET
DECEMBER 1996 ELIMINATING ENTRIES

G/L				Debit	Credit
			(A)		
SHI - 12201	a	SHI A/P TO SCM		2,459,254	
SCM-12201	b	SCM A/R FROM SHI			2,459,254
			(B)		
SCM-12901	c	SCM INTERCO A/P TO SHI - GHH		4,144,605	
SHI - 12901	d	SHI INTERCO A/R FROM SCM - GHH			4,144,605
			(C)		
SHI - 12902	e	SHI INTERCO A/P TO SCM - GENTRY		2,379,358	
SCM-12902	f	SCM INTERCO A/R FROM SHI - GENTRY			2,379,358
		TO ELIMINATE INTERCO RECEIVABLES/PAYABLES BETWEEN HOMEBUILDING COMPANIES			
			(D)		
SCM-12903	g	SCM INTERCO A/P TO SDC - GENTRY		4,663,344	
SHI - 265	h	SHI INTERCO NOTE TO SDC - ACQUISITION		1,432,265	
SHI - 12903	i	SHI INTERCO A/R FROM SDC - GENTRY			1,766,003
1000-206575	j	SDC A/R FROM SCM			4,204,106
1000-107230	k	SDC A/R FROM S HOMES			125,501
			(E)		
			(E)		
SCM-267	l	GOLDEN HERITAGE CASH ADVANCES FROM SDC		11,692,358	
1000-107260	m	SDC CASH ADVANCES TO GOLDEN HERITAGE			11,692,358
			(F)		
SCM-267	n	SCM INTERCO NOTE TO SDC - GH INTEREST		71,856	
SCM-268	o	SCM INTERCO NOTE TO SDC - SH INTEREST		63,790	
1000-107255	p	SDC INTERCO INTEREST A/R FROM HOMEBUILDING			135,646
			(G)		
SHI - 129	q	SHI INTERCO PAYABLE TO SDC		2,825	
SHI - 234	r	SHI INTERCO PAYROLL PAYABLE TO SDC		8,733	
SHI - 240	s	SHI INTERCO PAYROLL PAYABLE TO SDC		13,600	
SHI - 275	t	SHI INTERCO INTEREST PAYABLE TO SDC		17,307	
1000-107250	u	SDC A/R FROM GOLDEN HERITAGE			42,465
		TO ELIMINATE INTERCO RECEIVABLES/PAYABLES BETWEEN HOMEBUILDING COMPANIES AND SDC			
			(H)		
1000-176135	v	SDC INVESTMENT IN SHI - GOLDEN HERITAGE		1,794,677	
1000-176132	w	SDC INVESTMENT IN SHI - SUNCOR HOMES			223,493
SHI - P&L	x	SHI CURRENT YEAR LOSS			1,359,913
SHI - B/S	y	SHI ACCUMULATED LOSSES			211,271
		TO ELIMINATE INVESTMENT IN SHI ON SDC BOOKS			
SCM-P&L	z	SCM CURRENT YEAR INCOME	(I)	16,339	
SCM	aa	SCM ACCUMULATED INCOME		379,286	
1000-206576	bb	SDC INVESTMENT IN SCM			395,624
		TO ELIMINATE INVESTMENT IN SCM ON SDC BOOKS			
1000-235990	cc	DEFERRED INTERCO PROFIT HOME INVENTORY	(J)	1,075,417	1,075,417
		TO ELIMINATE BALANCE SHEET GROSS UP ON INTERCO LOT SALES BETWEEN SDC AND HOMEBUILDING			
TOTALS				30,215,014	30,215,014

EXHIBIT B Financial Data Schedule

The Claimant submits the following consolidated financial information:

1. Total Assets: $6,989,289,000

2. Total Operating Revenues: $1,817,760,000

3. Net Income: $181,180,000

EXHIBIT D

Map of the state of Arizona showing the following:

APS Service Area;

Major APS Power Plants, including joint ownership;

Principal APS Transmission Lines; and

Transmission Lines Operated for Others.

1800 M Street, N.W
Washington, D.C. 20036-5869
202-467-7000
Fax: 202-467-7176

Morgan, Lewis
& Bockius LLP
COUNSELORS AT LAW

Mary Ann K. Huntington
202-467-7622

August 19, 1999

99 AUG 19 PM 4:56
FEDERAL ENERGY REGULATORY COMMISSION

Mr. David P. Boergers
Secretary
Federal Energy Regulatory Commission
888 First Street, N.E.
Washington, D.C. 20426

Re: *APS Energy Services Company, Inc.*, Docket No. ER99-___-000

Dear Mr. Boergers:

On behalf of APS Energy Services Company, Inc., please find enclosed an original and 14 copies an Application for an Order Approving Market Based Rates.

If you have any questions, please feel free to call me at 202-467-7622.

Sincerely,

Mary Ann K. Huntington

Attorney for
APS Energy Services Company, Inc.

Enclosure

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

APS Energy Services Company, Inc.	)	Docket No. ER99-____-000

APPLICATION OF APS ENERGY SERVICES COMPANY, INC. FOR ORDER APPROVING MARKET-BASED RATES

Pursuant to Section 205 of the Federal Power Act, 16 U.S.C. § 824d, and Rule 205 of the Rules of Practice and Procedure of the Federal Energy Regulatory Commission ("FERC" or the "Commission"), 18 C.F.R. § 385.205 (1998), APS Energy Services Company, Inc. ("APSES") hereby submits for filing this Application for authorization to engage in wholesale power sales at market-determined prices. APSES requests that the Commission take the following actions: (1) accept its Market-Based Rate Tariff (the "Market Rate Tariff") for wholesale sales of energy and capacity, including ancillary services within the California Independent System Operator ("ISO"); (2) approve the code of conduct governing APSES' relationship with its public utility affiliate, Arizona Public Service Company ("APS"); and (3) grant waivers of certain of the Commission's regulations and blanket authorizations of other actions under the Commission's regulations. Pursuant to Section 35.3(a) of the Commission's regulations, APSES also requests an effective date of 60 days after this filing, or the date on which the Commission issues an order approving APSES' application for market-based rates, whichever is earlier.

I. DESCRIPTION OF APSES

APSES is an Arizona corporation formed in 1998, whose principal place of business is located at 400 East Van Buren Street, Phoenix, Arizona. APSES does not own or control electric

power generation, transmission, or distribution facilities. APSES was formed to provide unregulated energy and related energy services to customers throughout Arizona, California, and other states that have instituted retail direct access. APSES seeks authorization to engage in wholesale power marketing activities at negotiated market-based rates under the proposed Market Rate Tariff.

APSES is a subsidiary of Pinnacle West Capital Corporation which also owns APS. APSES, therefore, is an affiliate of APS, a public service corporation organized under the laws of the State of Arizona, which is engaged in the business of generating, transmitting, distributing, and selling electricity in all or part of eleven of Arizona's fifteen counties. APS is authorized to sell wholesale power and energy at market-based rates. Arizona Public Service Co., 79 FERC ¶ 61,022 (1997). In its order granting market-based rate authority to APS, the Commission found that APS does not possess market power. Arizona Public Service Co., 79 FERC at 61,098-99. APSES has no other utility affiliates.

II. COMMUNICATIONS

APSES respectfully requests that service of pleadings and deliveries of communications and correspondence concerning this matter be directed to the following:

Vicki G. Sandler, Vice President
APS Energy Services Company, Inc.
400 East Van Buren Street
Mail Station 8103
Phoenix, Arizona 85004
Phone: (602) 744-5045

Barbara Muller Champion, Senior Attorney
Arizona Public Service Company
P.O. Box 53999
Mail Station 9820
Phoenix, Arizona 85004
Phone: (602) 250-3547

Mary Ann K. Huntington
Morgan, Lewis & Bockius LLP
1800 M Street, N.W.
Washington, D.C. 20036
Tel: (202) 467-7622

Applicants request that the above-listed individuals be placed on the official service list compiled for this proceeding.

III. LIST OF MATERIALS SUBMITTED WITH THIS FILING

This filing contains the following materials:

1. Exhibit A - APSES' Market-Rate Tariff, including a form of service agreement;

2. Exhibit B - APSES' Code of Conduct governing its relationship with APS;

3. Exhibit C - Notice of Filing suitable for publication in the Federal Register, with an electronic version on diskette.

IV. REQUEST FOR MARKET-BASED RATE APPROVAL FOR APSES

The Commission traditionally has permitted an entity -- whether a public utility, an independent power producer, or a power marketer -- to engage in wholesale sales of power and energy at market-based rates if the entity can demonstrate that neither it nor any of its affiliates have market power in relevant markets for generation service and transmission service (or have adequately mitigated such market power) and that neither can erect barriers to entry. See, e.g., Heartland Energy Service, Inc., 68 FERC ¶ 61,223, at 62,060 (1994) ("Heartland"). In evaluating requests for market-based rates, the Commission also considers whether there is any evidence of, or potential for, affiliate abuse or reciprocal dealing between the applicant and its affiliates. Id. As demonstrated in this application and its supporting materials, APSES satisfies the Commission's criteria and should be granted authority to engage in wholesale power sales transactions at market-based rates, including sales of ancillary services into the California ISO.

In addition to governing the market-based sales of power and energy, the Market Rate Tariff will permit APSES to reassign transmission capacity, transmission rights, and associated ancillary services acquired for its own use under open access transmission tariffs. The Market

Rate Tariff permits APSES to resell such capacity and rights at a price not higher than the highest of (1) the price APSES originally paid for the service, (2) the transmission provider's maximum rate for the service on file at the time of the resale, or (3) APSES' own opportunity costs capped at the applicable transmission provider's cost of expansion at the time of the sale to the eligible customer.[1/] The resold service will be provided in accordance with the terms and conditions of service of the original transmission provider's applicable open access transmission tariff. APSES' proposed reassignment of transmission and associated ancillary services is wholly consistent with reassignment provisions the Commission previously has accepted. See, e.g., Alliant Services Company, 85 FERC ¶ 61,344 (1998); Select Energy, Inc., 85 FERC ¶ 61,290 (1998); Commonwealth Edison Co., 78 FERC ¶ 61,312 (1997).

A. Market Power

With respect to its market power concerns, the Commission generally requires that an entity seeking authorization to transact at market-based rates (1) demonstrate that the entire output of its or any of its affiliates' generating facilities is committed under long-term contracts, (2) demonstrate that the applicant or its affiliates already are authorized to sell power at market-based rates, or (3) submit a market analysis that indicates that neither the applicant nor its affiliates have generation dominance in the relevant markets. LG&E Power Marketing, Inc., 68 FERC ¶ 61,247, at 62,121 (1994).

In this case, APSES has demonstrated that its affiliate, APS, is already authorized to sell at market-based rates. See Arizona Public Service Co., 79 FERC at 61,098-101. APSES relies on the market power study that its affiliate, APS, relied on in support of its market-based rate

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1/ APSES will not charge a rate based on its opportunity costs absent a separate filing under Section 205 of the Federal Power Act.

application, which FERC accepted. See, e.g., Alliant Services Co., 85 FERC ¶ 61,344 (1998) (finding no market power based on affiliates' market study approved in earlier merger order); Louisville Gas and Electric Co., et al., 85 FERC ¶ 61,215 (1998) (finding no market power based on affiliates' market studies approved in earlier market-based rate application orders). Moreover, because APSES does not own or control any generating facilities, APSES has no market power in generation. As such, the Commission should reach the same conclusion here that it reached in Arizona Public Service Co. -- that APSES does not have generation market power.

B. Transmission Market Power

In order to ensure that applicants for market-based rate authority do not possess transmission market power, the Commission generally requires the applicant, or its affiliated public utility, to file or have on file open access transmission tariffs for the provision of comparable services. See, e.g., Southern Indiana Gas & Electric Company, 77 FERC ¶ 61,021 (1996). APS filed its open access tariff on July 9, 1996 (Docket No. OA96-153-000), and a revised open access tariff on July 12, 1996 (Docket No. ER96-2401-000). The Commission accepted the revised open access tariff for filing on September 9, 1996, effective on February 11, 1997.[2/]

APSES does not own any transmission facilities. Accordingly, the availability of open access transmission service over APS' transmission facilities under the APS transmission tariff eliminates the potential for any exercise of transmission market power by APSES.

2/ In addition, on June 18, 1999, the Commission issued a letter order accepting a Settlement governing APS' transmission rates filed on October 10, 1997, as amended October 24, 1997, in Docket Nos. OA96-153-000 and ER96-2401-000.

C. Barriers to Entry

In previous cases, the Commission has examined the possibility that an entity might be able to erect other barriers to entry as a possible ground for denying the authority to charge market-based rates. Heartland, 68 FERC at 62,062. Neither APSES nor APS are affiliated with any entities that could impose barriers to entry in the electric power generation business through their ownership or control of any resources or inputs that could be essential to market entry by competitors.

D. Affiliate Abuse and Reciprocal Dealing

In evaluating market-based rate applications of affiliated power marketers, the Commission also considers the potential for affiliate abuse and reciprocal dealing. The Commission has explained that affiliate abuse takes place when a public utility and an affiliated power marketer transact in ways that result in a transfer of benefits from the public utility (and the ratepayers) to the power marketer (and the shareholders). Heartland 68 FERC at 62,062; Wholesale Power Services, Inc., 72 FERC ¶ 61,284 (1995).

In this instance, APSES submits with this application a Code of Conduct governing its relationship with its public utility affiliate, APS. The Code of Conduct satisfies the Commission's information sharing and interaffiliate transaction pricing rules that protect against affiliate abuse. See, e.g., Duke Power, 84 FERC ¶ 61,235 (1998). The Code of Conduct is attached as Exhibit B. For these reasons, no potential for affiliate abuse arises from the grant of market-based rate authority to APSES. Id.

D. The Commission's Filing Requirements

Consistent with the Commission's requirements, APSES commits that it will file quarterly transaction summaries and satisfy the Commission's other standard reporting requirements for affiliated power marketers. See Southern Co. Services, Inc., 87 FERC ¶ 61,214 (1999); Horizon Energy Co., 81 FERC ¶ 61,368 (1997). Specifically, APSES will file umbrella service agreements for short-term transactions (one year or less) within 30 days of the date of commencement of service, to be followed by quarterly transaction summaries for specific sales. For long-term transactions (longer than one year), the actual service agreement for each transaction will be filed within 30 days after commencement of service. Southern Co. Services, Inc., 87 FERC slip op. at 17.

APSES commits that it will file a revised market power analysis every three years. This commitment is consistent with Commission precedent. Morgan Stanley Capital Group, Inc., 69 FERC ¶ 61,175 (1994) (as clarified in Engelhard Power Marketing, Inc., 70 FERC ¶ 61,250 (1995)).

V. REQUEST FOR EFFECTIVE DATE AND WAIVERS

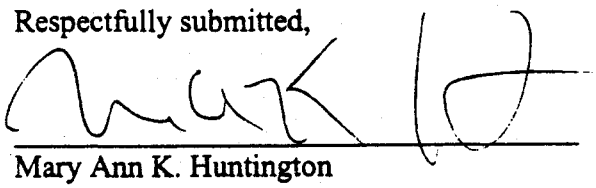
Consistent with the Commission's decisions in previous power marketer cases, APSES respectfully requests the Commission to waive the following requirements of the Commission's regulations: (1) waiver of accounting and reporting requirements under Parts 41, 101, and 141 of the Commission's regulations; (2) waiver of interlocking directorate filing requirements under Part 45 of the Commission's regulations, or, alternatively, permission to file abbreviated filings with respect to interlocking directorates under Part 45; and (3) waiver of the filing requirements of Subparts B and C of Part 35 of the Commission's regulations, other than Sections 35.12(a), 35.13(b), 35.15, and 35.16. See, e.g., AES Huntington Beach, L.L.C., 83 FERC ¶ 61,100 (1998).

Pursuant to Section 35.3(a) of the Commission's regulations, APSES respectfully requests that the Commission accept the Market Rate Tariff for filing and permit it to become effective the earlier of either sixty days after the date of this filing or the date the Commission grants acceptance.

VII. CONCLUSION

WHEREFORE, for the foregoing reasons, APSES requests the Commission to issue an order that grants: (1) authorization for APSES to engage in wholesale sales of electric power at market-based rates, including sales of ancillary services at market-based rates in the California market; (2) acceptance of the APSES Market Rate Tariff for filing effective sixty days after the filing of this application; (3) approval of the code of conduct governing APSES' relationship with APS; and (4) certain blanket authorizations; and (5) certain waivers of the Commission's regulations as stated herein.

Respectfully submitted,



Mary Ann K. Huntington
Morgan, Lewis & Bockius LLP
1800 M Street, N.W.
Washington, D.C. 20036
Tel: (202) 467-7000

Barbara Muller Champion, Senior Attorney
Arizona Public Service Company
P.O. Box 53999
Mail Station 9820
Phoenix, Arizona 85072-3999
Phone: (602) 250-3547

Attorneys for
APS Energy Services Company, Inc.

Dated: August 19, 1999

Exhibit A

APS Energy Services Company, Inc.

Market-Based Rate Tariff

APS Energy Services Company, Inc.

MARKET-BASED RATE TARIFF

1. Availability: APS Energy Services Company, Inc. ("APSES") makes electric capacity or energy available for sale for resale under this Rate Schedule to any purchaser.

2. Applicability: This schedule is applicable to all sales of electric capacity or energy by APSES not otherwise subject to a particular rate schedule of APSES, but shall not apply to the sales of electric capacity or energy to, or the purchase of electric capacity or energy from Arizona Public Service Company ("APS").

   This schedule also is applicable to the reassignment of transmission capacity, transmission rights and associated ancillary services, that APSES has acquired for its own use on the transmission systems of transmission providers.

3. Rates: All sales of electric capacity or energy shall be made at rates established by agreement between the purchaser and APSES.

4. Other Terms and Conditions:

   All other terms and conditions shall be established by agreement between the purchaser and APSES.

   APSES will not sell electric capacity or energy to, or purchase electric capacity or energy from APS, absent a separate filing with FERC pursuant to Section 205 of the Federal Power Act.

5. Effective Date:

   This Rate Schedule shall be effective on the date established by FERC.

6. Reassignment of Transmission Rights:

   APSES may reassign transmission capacity, transmission rights, and associated ancillary services that it has reserved for its own use at a price not to exceed the highest of: (1) the original transmission rate paid by APSES; (2) the applicable transmission provider's maximum stated firm transmission rate on file at the time of the transmission reassignment; or (3) APSES's own opportunity costs, capped at the applicable transmission provider's cost of expansion at the time of the sale to the eligible

customer. APSES will not recover opportunity costs in connection with reassignment without making a separate filing under Section 205. Except for the price, the terms and conditions under which the reassignment is made shall be under the terms and conditions governing the original grant by the transmission provider. Transmission and associated ancillary services may only be reassigned to a customer eligible to take service under the transmission provider's open access transmission tariff or other transmission rate schedules. APSES will report the name of the assignee in its quarterly reports.

APS Energy Services Company, Inc.

MARKET-BASED RATE TARIFF

SERVICE AGREEMENT

This Service Agreement, dated as of _____, is entered into by and between APS Energy Services Company, Inc. ("APSES") and _____ ("Customer"), pursuant to APSES's Market-Based Rate Tariff, FERC Electric Tariff No. 1.

Each transaction hereunder will be carried out under terms and conditions as agreed upon by APSES and the Customer in accordance with the terms and conditions of the Rate Schedule.

IN WITNESS WHEREOF, APSES and Customer have caused this Service Agreement to be executed by their respective authorized officials as of the date first above written.

Customer	**APS Energy Services Company, Inc.**
_____	
Customer	
_____	_____
Signature of Representative Date	Signature of Representative Date
_____	_____
Name of Representative	Name of Representative
_____	_____
Title of Representative	Title of Representative

Exhibit B

APS Energy Services Company, Inc.

Code of Conduct

APS ENERGY SERVICES COMPANY, INC.

STATEMENT OF POLICY AND CODE OF CONDUCT WITH RESPECT TO THE RELATIONSHIP BETWEEN APS ENERGY SERVICES COMPANY, INC. AND ARIZONA PUBLIC SERVICE COMPANY

The following Code of Conduct will govern the relationship between (1) APS Energy Services Company, Inc. ("APSES") and any other marketer affiliates that may be authorized by the Federal Energy Regulatory Commission to engage in sales for resale of energy and capacity at market-based rates (together with APSES, the "Marketing Affiliates") and (2) Arizona Public Service Company ("APS").

Marketing of Power

1. To the maximum extent practical, the employees of the Marketing Affiliates will operate separately from the employees of APS.

2. All market information shared by APS with the Marketing Affiliates will be disclosed simultaneously to the public. This includes all market information, including but not limited to, any communication concerning power or transmission business, present or future, positive or negative, concrete or potential. Shared employees in a support role are not bound by this provision, but they may not serve as an improper conduit of information to non-support personnel.

3. Sales of any non-power goods or services by APS, including sales made through affiliated EWGs or QFs, to the Marketing Affiliates will be at the higher of cost or market price.

4. Sales of any non-power goods or services by the Marketing Affiliates to APS will not be at a price above market.

Exhibit C

APS Energy Services Company, Inc.

Notice of Filing

UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

APS Energy Services Company, Inc.	)	**Docket No. ER99-_____**

NOTICE OF FILING
(____, 1999)

Take notice that on _____, APS Energy Services Company, Inc. ("APSES") filed an application for an order authorizing it to make wholesale sales of electric power at market-based rates and approving the Code of Conduct governing its relationship with its affiliated public utility.

Any person desiring to be heard or to protest said filing should file a motion to intervene or protest with the Federal Energy Regulatory Commission, 888 First Street, N.E., Washington, D.C. 20426, in accordance with Rules 211 and 214 of the Commission's Rules of Practice and Procedures (18 C.F.R. § 385.211 and 18 C.F.R. § 385.214). All such motions or protests should be filed on or before _____, 1999. Protests will be considered by the Commission in determining the appropriate action to be taken, but will not serve to make protestants parties to the proceedings. Any person wishing to become a party must file a motion to intervene. Copies of this filing are on file with the Commission and are available for public inspection. This filing may also be viewed on the Internet at http://www.ferc.fed.us/online/rims.htm (call 202-208-2222 for assistance).

David P. Boergers
Secretary

CERTIFICATE OF SERVICE

I hereby certify that I have this day served the foregoing document upon each person designated on the official service list compiled by the Secretary in this proceeding. Dated at Washington, D.C., this 19th day of August, 1999.

Mary Ann K. Huntington
Morgan, Lewis & Bockius LLP
1800 M Street, N.W.
Washington, D.C. 20036
(202) 467-7622

Attorney for
APS Energy Services Company, Inc.

89 FERC ¶ 61,024

FEDERAL ENERGY REGULATORY COMMISSION
WASHINGTON, D.C. 20426

October 13, 1999

Docket Nos. ER99-4102-000
ER99-4122-000
ER99-4162-000
ER99-4282-000

Andrews & Kurth LLP
ATTN: Anthony J. Ivancovich, Esq.
Attorney for Milford Power Company, LLC
1701 Pennsylvania Avenue, N.W.
Suite 300
Washington, D.C. 20006-5805

Morgan, Lewis & Bockius LLP
ATTN: Mary Ann K. Huntington, Esq.
Attorney for APS Energy Services Company, Inc.
1800 M Street, N.W.
Washington, D.C. 20036-5869

Dewey Ballantine LLP
ATTN: Zori G. Ferkin, Esq.
Attorney for Mantua Creek Generating Company, L.P.
Attorney for Athens Generating Company, L.P.
1775 Pennsylvania Avenue, N.W.
Washington, D.C. 20006-4605

Dear Sir and Madams:

You submitted for filing with the Commission rate schedules under which applicants will engage in wholesale electric power and energy transactions at market-based rates. Your submittals, as modified below, comply with the Commission's requirements for market-based rates and are accepted for filing. They are designated and made effective as indicated in Appendix A to this order.

APS Energy Services Company, Inc. (APSES) requests authority to engage in sales of ancillary services at market-based rates within the California ISO. However, APSES's rate schedule does not specify the ancillary services it intends to provide nor does it restrict ancillary service sales to the markets administered by the California ISO. We will

accept APSES's proposed rate schedule. However, we will direct APSES, within 30 days of the date of this order, to revise its proposed rate schedule to specify each of the ancillary services it seeks to provide. Similarly, we will direct APSES, within 30 days of the date of this order, to revise its proposed rate schedule to limit its authority to sell ancillary services to sales into the markets administered by the California ISO.

Mantua Creek Generating Company, L.P. (Mantua Creek) requests authority to engage in the sale of certain ancillary services (Energy Imbalance and Operating Reserves) at market-based rates into the PJM Power Exchange. Athens Generating Company, L.P. (Athens) also requests authority to make sales of certain ancillary services (listed in its proposed rate schedule) at market-based rates into the markets administered by the PJM Power Exchange, ISO New England, and the New York ISO.[1] We will grant these requests.

Any waivers or authorizations requested by the applicants are granted to the extent specified in Appendix B to this order. Waiver of the prior or advance notice requirements, if requested, is granted to the extent specified in Appendix A. The applicants must comply with the reporting requirements and other requirements specified in Appendix B to this order.[2]

The codes of conduct submitted by the applicants are accepted if consistent with Appendix C, which reflects requirements adopted in previous Commission orders. Any code of conduct inconsistent with Appendix C is rejected and in such case Appendix C has been designated as the applicant's code of conduct. The codes of conduct submitted by the applicants covered by this order are consistent with Appendix C.

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[1]See Atlantic City Electric Company, et al., 86 FERC ¶ 61,248 (1999); Central Hudson Gas & Electric Corporation, et al., 86 FERC ¶ 61,062 (1999); New England Power Pool, 85 FERC ¶ 61,379 (1998).

[2]On May 27, 1999, the Commission issued an order in which it modified the reporting requirements for long-term transactions applicable to public utilities without ownership or control over generation or transmission facilities that are authorized to sell power at market-based rates (power marketers). Southern Company Services, et al., 87 FERC ¶ 61,214 (1999), reh'g pending (Southern). Specifically, with respect to any long-term transaction agreed to by a power marketer after 30 days from the date of issuance of a final order in the Southern case, the power marketer must file a service agreement with the Commission within 30 days after service commences, rather than reporting transactions thereunder in its quarterly transaction summaries.

Pursuant to Rule 214 of the Commission's Rules of Practice and Procedure, 18 C.F.R. § 385.214 (1999), an entity's filing of a timely notice of intervention or a timely, unopposed motion to intervene in a proceeding makes it a party to that proceeding.

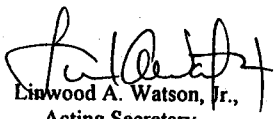
Should an applicant or any of its affiliates deny, delay, or require unreasonable terms, conditions, or rates for natural gas fuel or services to a potential electric competitor in bulk power markets, then that electric competitor may file a complaint with the Commission that could result in the applicant's or its affiliate's authority to sell power at market-based rates being suspended.[3]

Sales of accounts receivable are not dispositions of jurisdictional facilities and are not within the scope of section 203 of the FPA. To the extent an applicant seeks a case-specific finding on this or any related point, it may file a petition for a declaratory order with the Commission.

APSES, Mantua Creek and Athens seek Commission approval to reassign transmission capacity. We find the request of APSES is consistent with our requirements. The reassignment provisions submitted by Athens and Mantua Creek fail to note that reassignments of capacity are subject to the terms and conditions of the transmission provider's open access tariff.[4] Athens and Mantua Creek will be required to revise their proposed rate schedules to remedy this deficiency.

Milford, Mantua Creek and Athens must inform the Commission of the dates service commences.

By direction of the Commission.



Linwood A. Watson, Jr.,
Acting Secretary.

[3]See, e.g., Louisville Gas & Electric Co., 62 FERC ¶ 61,016 at 61,148 (1993).

[4]See, e.g., Enron Power Marketing, Inc., 81 FERC ¶ 61,277 at 62,361 (1997).

APPENDIX A

Applicants are hereby informed of the following rate schedule designations:

Milford Power Company, L.L.C.
Docket No. ER99-4102-000
Rate Schedule Designation
Effective Date: Date of Commencement of Service

Designation	Description
FERC Electric Tariff, Original Volume No. 1 Original Sheet No. 1	Market-Based Rate Tariff

APS Energy Services Company, Inc.
Docket No. ER99-4122-000
Rate Schedule Designations
Effective Date: Date of Issuance of Order

	Designation	Description
(1)	Rate Schedule FERC No. 1	Market-Based Rate Schedule
(2)	Supplement No. 1 to Rate Schedule FERC No. 1	Code of Conduct

Mantua Creek Generating Company, L.P.
Docket No. ER99-4162-00
Rate Schedule Designations
Effective Date: Date of Commencement of Service

Designation	Description
FERC Electric Tariff Original Volume No. 1 Original Sheet Nos. 1 and 2	Market-Based Rate Tariff and Code of Conduct

Athens Generating Company, L.P.
Docket No. ER99-4282-000
Rate Schedule Designation
Effective Date: Date of Commencement of Service

Designation	Description
FERC Electric Tariff, Original Volume No. 1 Original Sheet Nos. 1-3	Market-Based Rate Tariff with Code of Conduct

APPENDIX B

(1) If requested, waiver of Parts 41, 101, and 141 of the Commission's regulations, with the exception of 18 C.F.R. § § 141.14, .15 (1999), is granted. Licensees remain obligated to file the Form No. 80 and the Annual Conveyance Report.

(2) Within 30 days of the date of this order, any person desiring to be heard or to protest the Commission's blanket approval of issuances of securities or assumptions of liabilities by those applicants who have sought such approval should file a motion to intervene or protest with the Federal Energy Regulatory Commission, 888 First Street, N.E., Washington, D.C. 20426, in accordance with Rules 211 and 214 of the Commission's Rules of Practice and Procedure, 18 C.F.R. §§ 385.211 and 385.214.

(3) Absent a request to be heard within the period set forth in Paragraph (2) above, if the applicants have requested such authorization, the applicants are hereby authorized to issue securities and assume obligations or liabilities as guarantor, indorser, surety, or otherwise in respect of any security of another person; provided that such issue or assumption is for some lawful object within the corporate purposes of the applicants, compatible with the public interest, and reasonably necessary or appropriate for such purposes.

(4) If requested, until further order of this Commission, the full requirements of Part 45 of the Commission's regulations, except as noted below, are hereby waived with respect to any person now holding or who may hold an otherwise proscribed interlocking directorate involving the applicants. Any such person instead shall file a sworn application providing the following information:

(a) full name and business address; and

(b) all jurisdictional interlocks, identifying the affected companies and the positions held by that person.

(5) The Commission reserves the right to modify this order to require a further showing that neither the public nor private interests will be adversely affected by continued Commission approval of the applicants' issuances of securities or assumptions of liabilities, or by the continued holding of any affected interlocks.

(6) If requested, waiver of the provisions of Subparts B and C of Part 35 of the Commission's regulations, with the exception of sections 35.12(a), 35.13(b), 35.15 and 36.16, is granted for transactions under the rate schedules at issue here.

(7) (a) Applicants who own generating facilities may file umbrella service agreements for short-term power sales (one year or less) within 30 days of the date of commencement of short-term service, to be followed by quarterly transaction summaries of specific sales (including risk management transactions if they result in actual delivery of electricity). For long-term transactions (longer than one year), applicants must submit the actual individual service agreement for each transaction within 30 days of the date of commencement of service. To ensure the clear identification of filings, and in order to facilitate the orderly maintenance of the Commission's files and public access to documents, long-term transaction service agreements should not be filed together with short-term transaction summaries. For applicants who own, control or operate facilities used for the transmission of electric energy in interstate commerce, prices for generation, transmission and ancillary services must be stated separately in the quarterly reports and long-term service agreements.

(b) Applicants who do not own generating facilities must file quarterly reports detailing the purchase and sale transactions undertaken in the prior quarter (including risk management transactions if they result in actual delivery of electricity). Applicants who are power marketers should include in their quarterly reports only those risk management transactions that result in the actual delivery of electricity.

(8) The first quarterly report filed by an applicant in response to Paragraph (7) above will be due within 30 days of the end of the quarter in which the rate schedule is made effective.

(9) Each applicant must file an updated market analysis within three years of the date of this order, and every three years thereafter. The Commission reserves the right to require such an analysis at any time. The applicants must also inform the Commission promptly of any change in status that would reflect a departure from the characteristics the Commission has relied upon in approving market-based pricing. These include, but are not limited to: (a) ownership of generation or transmission supplies; or (b) affiliation with any entity not disclosed in the applicants' filing that owns generation or transmission facilities or inputs to electric power production, or affiliation with any entity that has a franchised service area. Alternatively, the applicants may elect to report such changes in conjunction with the updated market analysis required above. Each applicant must notify the Commission of which option it elects in the first quarterly report filed pursuant to Paragraph (7) above.

APPENDIX C

[APPLICANT]
SUPPLEMENT NO. _ TO RATE SCHEDULE NO. _

STATEMENT OF POLICY
AND CODE OF CONDUCT
WITH RESPECT TO THE RELATIONSHIP BETWEEN
[POWER MARKETER] AND [PUBLIC UTILITY]

Marketing of Power

1. To the maximum extent practical, the employees of [Power Marketer] will operate separately from the employees of [Public Utility].

2. All market information shared between [Public Utility] and [Power Marketer] will be disclosed simultaneously to the public. This includes all market information, including but not limited to, any communication concerning power or transmission business, present or future, positive or negative, concrete or potential. Shared employees in a support role are not bound by this provision, but they may not serve as an improper conduit of information to non-support personnel.

3. Sales of any non-power goods or services by [Public Utility], including sales made through its affiliated EWG's or QF's, to [Power Marketer] will be at the higher of cost or market price.

4. Sales of any non-power goods or services by the [Power Marketer] to [Public Utility] will not be at a price above market.

Brokering of Power

To the extent [Power Marketer] seeks to broker power for [Public Utility]:

5. [Power Marketer] will offer [Public Utility's] power first.

6. The arrangement between [Power Marketer] and [Public Utility] is non-exclusive.

7. [Power Marketer] will not accept any fees in conjunction with any Brokering services it performs for [Public Utility].

91 FERC ¶ 61,290

UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

Before Commissioners: James J. Hoecker, Chairman;
William L. Massey, Linda Breathitt,
and Curt Hébert, Jr.

Pinnacle West Capital Corporation
Arizona Public Service Company
APS Energy Services Company, Inc.

Docket No. ER00-2268-000

ORDER CONDITIONALLY ACCEPTING FOR FILING PROPOSED MARKET-BASED RATE TARIFF AND CODE OF CONDUCT, AND REVISED MARKET-BASED RATE TARIFFS AND CODES OF CONDUCT

(Issued June 20, 2000)

In this order, the Commission conditionally accepts for filing a proposed market-based rate tariff and code of conduct by Pinnacle West Capital Corporation (Pinnacle), along with revised market-based rate tariffs and codes of conduct for two of Pinnacle's affiliates.

BACKGROUND

On April 21, 2000, Pinnacle[1] filed an application, under section 205 of the Federal Power Act (FPA),[2] seeking: (1) authority for Pinnacle to engage in wholesale sales of electric power at market-based rates, including market-based rate sales to its affiliates, and sales of ancillary services within the California Independent System Operator (California ISO) market; (2) authority for Pinnacle to reassign transmission capacity; (3) approval of revised market-based rate tariffs that would allow APS and

[1]Pinnacle submitted the filing on its own behalf and on behalf of its affiliates APS and APS Energy Services Company (APSES). This order collectively refers to these three companies as the "Pinnacle West Companies."

[2]16 U.S.C. § 824d (1994).

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JUN 20 2000

000621-0249-1

APSES to transact business with affiliates at market-based rates;[3] and (4) approval of a code of conduct for Pinnacle and proposed modifications to the codes of conduct of APS and APSES.[4]

The Pinnacle West Companies note in their application that the Arizona Corporation Commission (Arizona Commission) is in the process of modifying its rules on retail electric competition within Arizona to allow full retail choice. On October 6, 1999, the Arizona Commission approved a settlement agreement between APS and several customer groups and consumer advocates resolving retail electric competition-related issues and approving unbundled tariffs. Pinnacle's application seeks authority to engage in wholesale power marketing activities at market-based rates. The Pinnacle West Companies also propose revisions to the market-based rate tariffs and codes of conduct of APS and APSES to permit them to engage in inter-affiliate transactions at market-based rates.

Notice of the filing was published in the Federal Register, with comments, protests, and interventions due on or before May 12, 2000.[5]

---

[3]Pinnacle is the parent corporation of both APS and APSES. APS is a public service corporation engaged in the business of generating, transmitting, and distributing electricity in all or part of eleven of Arizona's fifteen counties. The Commission granted APS market-based rate authority in Arizona Public Service Company, 79 FERC ¶ 61,022 (1997).

APSES is a retail marketer of electricity and energy-related services in Arizona and California. APSES also engages in wholesale marketing and brokering of electricity that it states is largely incidental to its retail function. The Commission granted APSES market-based rate authority in APS Energy Services Company, Inc., 89 FERC ¶ 61,024 (1999).

[4]As discussed below, the Pinnacle West Companies propose to eliminate (or, in the case of Pinnacle, not include) the code of conduct provisions that require simultaneous disclosure to the public of all market information shared between APS and its affiliates.

[5]65 Fed. Reg. 25,479 (2000).

Interventions and Protests

The Arizona Commission filed a notice of intervention. Timely motions to intervene were filed by Arizona Power Authority (APA), Salt River Agricultural Improvement and Power District (Salt River), New West Energy Corporation (New West), and Citizens Utilities Company (Citizens). Timely motions to intervene or protests were filed by Tucson Electric Power Company (Tucson) and jointly by a number of electrical and irrigation districts in the state of Arizona (Arizona Districts).[6] Late-filed motions to intervene were filed by Williams Energy Marketing & Trading Company (Williams Energy) and the Navajo Tribal Utility Authority (NTUA).

APA states that 14 of its customers have power contracts with APS. Although APA does not formally protest Pinnacle's filing, its motion to intervene raises concerns about possible affiliate abuse and increased purchased power costs. Tucson argues that Pinnacle's application raises issues about market power and affiliate abuse. Arizona Districts raise similar concerns and also argue that Pinnacle's filing should be rejected because it fails to meet the Commission's filing requirements under section 205 of the FPA for sales to affiliates at market-based rates.

On May 30, 2000, the Pinnacle West Companies filed a request for leave to file an answer and an answer to APA's motion to intervene and to the protests of Arizona Districts and Tucson.

DISCUSSION

As a preliminary matter, the Arizona Commission's notice of intervention and the timely, unopposed motions to intervene of APA, Salt River, New West, Citizens, Tucson and Arizona Districts serve to make them parties to this proceeding. We will grant the late-filed motions to intervene of Williams Energy and NTUA, given the early stage of this proceeding and the absence of any undue prejudice or delay. See 18 C.F.R. § 385.214 (1999). While Rule 213(a)(2) of the Commission's Rules of Practice and Procedure (18 C.F.R. §385.213(a)(2) (1999)) generally prohibits the filing of an answer

[6]Arizona Districts are comprised of: Aguila Irrigation District; Buckeye Water Conservation & Drainage District; Electrical District No. 1 of Pinal County; Electrical District No. 3 of Pinal County; Electrical District No. 6 of Pinal County; Electrical District No. 7 of Maricopa County; Electrical District No. 8 of Maricopa County; Harquahala Valley Power District; Maricopa County Municipal Water Conservation District No. 1; McMullen Valley Water Conservation & Drainage District; Roosevelt Irrigation District; and Tonopah Irrigation District.

to protests, we will accept the Pinnacle West Companies' answer in light of the representations made by the Pinnacle West Companies that assist in our understanding and resolution of the issues in this proceeding.

A. Market-Based Rates

The Commission allows power sales at market-based rates if the seller and its affiliates do not have, or have adequately mitigated, market power in generation and transmission and cannot erect other barriers to entry. For an affiliate of a transmission-owning public utility to demonstrate the absence or mitigation of market power, the public utility must have on file with the Commission an open access transmission tariff for the provision of comparable services. The Commission also considers whether there is evidence of affiliate abuse or reciprocal dealing.[7]

As we explain below, we find that Pinnacle's proposed market-based rate tariff, with an exception discussed below, meets these standards. Accordingly, we will conditionally accept the proposed tariff for filing, without suspension or hearing, to become effective on June 20, 2000, 60 days after the date of filing.

1. Generation Market Power

Pinnacle does not own or control any generating facilities. Further, the Commission has recently evaluated the generation dominance of Pinnacle's affiliates in Docket No. ER00-1875-000, and we are not aware of any material changes in circumstances that would require a new analysis.[8] Thus, we find that Pinnacle meets the Commission's generation market power standard for approval of market-based rates.

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[7] E.g., Progress Power Marketing, Inc., 76 FERC ¶ 61,155 at 61,919 (1996), letter order approving settlement, 79 FERC ¶ 61,149 (1997); Northwest Power Marketing Company, L.L.C., 75 FERC ¶ 61,281 at 61,889 (1996); accord Heartland Energy Services, Inc. et al., 68 FERC ¶ 61,223 at 62,060-063 (1994) (Heartland).

[8] On March 14, 2000, APS submitted an updated generation market study in Docket No. ER00-1875-000. This market study was accepted for filing by the Director, Division of Corporate Applications, Office of Markets, Tariffs, and Rates, acting under delegated authority, in an unpublished letter order issued on May 2, 2000.

2. Transmission Market Power

When an affiliate of a transmission-owning public utility seeks authorization to charge market-based rates, the Commission has required the public utility to have an open access transmission tariff on file before granting such authorization. Pinnacle does not own any transmission facilities. Its affiliate, APS, filed an open access transmission tariff with the Commission in Docket No. OA96-153-000, as amended in Docket No. ER96-2401-000. Both filings were accepted by the Commission in a letter order dated June 18, 1999. Thus, we find that Pinnacle meets the Commission's transmission market power standard for approval of market-based rates.

3. Other Barriers to Entry/Reciprocal Dealing

Based on our review of the application, we are satisfied that there are no barriers to entry or reciprocal dealing considerations of concern here.

4. Affiliate Abuse

The Pinnacle West Companies propose to engage in affiliate transactions at market-based rates.[9] Pinnacle proposes not to include in its code of conduct provisions requiring that all market information shared among the affiliates be disclosed simultaneously to the public.[10] In support of their proposal to make sales to affiliates, Pinnacle argues that there is no risk of harm to APS's retail or wholesale customers and, therefore, no potential for affiliate abuse. Pinnacle states that, in order to effectuate retail access, a substantial portion of APS's retail customers have already been authorized to choose their generation providers and that APS's remaining retail customers have been provided rate reductions that will remain in effect until 2004, well after the anticipated full retail choice date of 2001.[11] Pinnacle argues that the Commission has found that

[9]In this regard, APS and APSES propose to remove from their market-based rate tariffs the provision prohibiting affiliate sales absent a separate filing with the Commission under § 205 of the FPA. Pinnacle's proposed tariff does not include such a provision.

[10]APS and APSES propose to remove a similar provision from their codes of conduct.

[11]Based on a settlement agreement approved by the Arizona Commission, Pinnacle states that full retail choice is expected to be implemented in 2001. Pinnacle Application (continued...)

there is no potential for affiliate abuse where a public utility's retail customers have retail choice or are protected by a rate freeze. Therefore, Pinnacle states that APS's retail customers are protected from affiliate abuse concerns.

In addition, Pinnacle proposes to mitigate any potential harm to wholesale customers by putting in place measures that will protect the customers from the improper pass-through of costs associated with affiliate transactions. In the case of wholesale customers whose contracts include a pricing provision based on APS's system incremental cost, Pinnacle proposes to cap the pass-through of costs to such wholesale customers at the lesser of APS's system incremental costs (SIC) or prices calculated based on the Palo Verde Index. In the case of wholesale customers whose contracts contain a FAC, Pinnacle proposes to cap the pass-through of costs flowing through the FAC at the lesser of actual cost or historical cost based on an average of 1998 and 1999 fuel and eligible purchased power costs for the relevant monthly period.

Tucson requests that the Commission impose adequate safeguards to ensure that APS's sales to its affiliates are priced no lower than the higher of APS's costs or the relevant market price. Tucson also opposes Pinnacle West Companies' request for a waiver of certain of the Commission's code of conduct restrictions.

Tucson suggests that the Commission should impose the same safeguards (i.e., a price floor on sales from a traditional public utility to its affiliated marketers) that the Commission adopted in Detroit Edison Company, et al., 80 FERC ¶ 61,348 at 62,197-98 (1997) (Detroit Edison). Tucson argues that it is not aware of any previous Commission case that granted market-based rate approval and a blanket waiver of the prohibition against sales from a traditional utility to its affiliated marketers unless that approval was conditioned on a Detroit Edison price floor. Tucson notes that Pinnacle West Companies cite Green Power Partners I, LLC, et al., 88 FERC ¶ 61,005 (1999) (Green Power Partners) for the proposition that codes of conduct may be waived in situations where traditional public utilities lack captive ratepayers. However, Tucson argues that, in Green Power Partners, the Commission granted waiver of the affiliate sales restrictions for sales from a power marketer to a traditional public utility, not for sales from the traditional public utility to affiliated marketers (which is part of the Pinnacle West Companies' proposals). Tucson further argues that, although the Commission has granted some code of conduct waivers in cases where there are no captive ratepayers or where captive ratepayers were held harmless, the Commission has never granted a

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[11](...continued)
at 12 & n.29.

blanket waiver of the Detroit Edison standard for sales from traditional utilities to affiliated power marketers without imposing some type of pricing floor.

APA argues that, if Pinnacle is granted market-based rate authority for affiliate sales, APA's customers may suffer a rate increase as a result of the pass-through of increased purchase power costs. Further, APA argues that granting Pinnacle authority to share market information with its affiliates without simultaneous disclosure to the public could directly affect the market for wholesale power in Arizona.

Arizona Districts request that the Commission require Pinnacle to revise its code of conduct to require that all market information shared by APS with Pinnacle must simultaneously be disclosed to the public. Arizona Districts similarly ask the Commission to deny the proposed modification to the codes of conduct of APS and APSES to delete the information sharing requirement. Arizona Districts argue that this requirement is a valid and essential safeguard to prevent self-dealing and affiliate abuse.

Arizona Districts also argue that the Pinnacle West Companies have failed to explain why the Commission should allow them to make affiliate sales without making a separate section 205 filing. Arizona Districts warn that granting this request would have implications not merely for the instant filing but also for potential future transactions and affiliates not revealed in the instant filing.[12]

Commission Conclusion

As the Commission has explained in previous cases, there is a concern whenever a traditional public utility can transact with an affiliated power marketer in such a way as to transfer benefits from a power sale from the public utility's captive ratepayers to the shareholders.[13] This can occur if the public utility can sell power to its affiliated power marketer at below-market prices or if the power marketing affiliate can sell power to the public utility at a price above the prevailing market price.

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[12]Arizona Districts' Protest at 8 & n.4 (citing Pinnacle Application at 3-4, which describes Pinnacle West Energy Corporation, a recently formed company, that Pinnacle states will be engaged in the business of owning and operating exempt wholesale generating facilities).

[13]See GPU Advanced Resources, Inc., 81 FERC ¶ 61,335 at 62,539 (1997) (GPU); Detroit Edison, 80 FERC at 62,197.

In the instant filing, there will be affiliate sales: (1) from the traditional public utility (APS) to the power marketers (APSES and Pinnacle); and (2) from the power marketers to the traditional public utility. Thus, the Commission must ensure that the sale prices are not too low,[14] nor too high,[15] because, in either of these instances, the costs would be absorbed by captive ratepayers.

Pinnacle suggests that there is no potential for affiliate abuse in any event because APS's retail customers are protected by a rate reduction and freeze and/or their abilities to choose their electric suppliers and because the Pinnacle West Companies' mitigation proposals protect APS's wholesale customers against cost shifting.

With regard to APS's retail customers, Pinnacle states that a substantial portion of APS's retail customers are already authorized to choose their generation provider and that those customers not already authorized to make this choice will: (1) be eligible to make this choice beginning on January 1, 2001; and (2) are provided with a retail rate reduction until 2004. Pinnacle further states that, although APS has a right to propose rate changes for emergencies, retail rates are frozen at reduced levels "for all practical purposes."[16]

While APS has the right to propose retail rate changes in emergencies, APS has committed to notify the Commission if it ever makes a filing with the Arizona Commission invoking this right.[17] Moreover, if such a situation arises, we reserve the right to take additional steps in order to protect ratepayers.

As to APS's captive wholesale customers, Pinnacle proposes to protect these customers from potential affiliate abuse by: (1) for customers with pricing provisions based on the SIC, capping the SIC component at prices set by a competitive regional market hub (i.e., the Palo Verde Index); and (2) for wholesale customers with a FAC, limiting the pass-through of costs flowing through the wholesale FAC to the lesser of actual costs or a historical average. We find Pinnacle's proposal to cap SIC prices at levels based on the Palo Verde Index a reasonable means to avoid potential affiliate

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[14]See Detroit Edison, 80 FERC at 61,348.

[15]See GPU, 81 FERC at 62,539. See also First Energy Trading & Power Marketing, Inc., 84 FERC ¶ 61,214 at 62,037 (1998) (First Energy).

[16]Pinnacle Application at 12.

[17]Pinnacle Application at n.30.

abuse.[18] As is the general practice in the industry, these rates are used to price coordination transactions that occur on an as-available basis when both parties can agree on a price that satisfies their own economic interests.

While we are satisfied by Pinnacle's proposal based on the Palo Verde Index (because the Palo Verde Index is an open, transparent, well-recognized index of market prices in the Palo Verde region and because Pinnacle does not control prices under the Palo Verde Index), we still have concerns about the proposed safeguards for Pinnacle's FAC customers.

APS proposes to limit fuel costs under the FAC to the lesser of historical costs or actual costs, in lieu of requiring the affiliates to continue to abide by the Commission's rules on affiliate abuse. Compliance with the Commission's rules on affiliate abuse, however, could result in FAC costs that are lower than historical costs or actual costs. For example, our code of conduct is designed to prevent the traditional utility from diverting transactions that are beneficial to ratepayers to its affiliate for the benefit of shareholders. Such transactions could reduce fuel and purchased power costs below historic levels and such reductions would be lost under Pinnacle's proposed FAC cap.

Based on this concern, we encourage Pinnacle to explore with its FAC customers other options to prevent potential affiliate abuse, including revisions to the FAC or the use of another rate recovery method, in lieu of the FAC, for these customers. In this regard, the parties may wish to avail themselves of the Commission's Alternate Dispute Resolution (ADR) procedures, including procedures facilitated by our Dispute Resolution Service, although we will not mandate that this approach be used. If Pinnacle follows this approach, it must submit a compliance filing on its rates for its FAC customers. This proposal should incorporate any agreement it reaches with its customers on this issue or, barring agreement, Pinnacle may propose other methods to protect these customers from affiliate abuse.

Alternatively, Pinnacle must abide by the pricing and other safeguards established in Detroit Edison and GPU. If Pinnacle chooses this approach, it must: (1) notify the Commission of its selection within 15 days of the date of issuance of this order; and (2)

[18]The four rate schedules affected are: APS's cost-based coordination sales tariff (under which approximately 30 customers are currently served) and bilateral agreements with three customers (Citizens Utility Company, Colorado River Commission of Nevada, and Tohono O'odham Utility Authority). None of these customers have objected to Pinnacle's proposal.

file revised market-based rate tariffs reflecting the Detroit Edison and GPU safeguards within 30 days of the date of issuance of this order.

We find Arizona Districts' argument that the Pinnacle West Companies seek "a blanket authorization for inter-affiliate transactions without separate Section 205 filings" to be misplaced.[19] The application in this proceeding (seeking authority to engage in affiliate sales at market-based rates) constitutes the separate filing under section 205 that is required by the Commission.[20]

Moreover, in response to Arizona Districts' concern that the instant filing seeks blanket authority for affiliate sales with affiliates not yet in existence, the Pinnacle West Companies represent in their answer that they intend to make a separate filing or filings with the Commission to seek authority to engage in inter-affiliate transactions at market-based rates with Pinnacle West Energy Corporation once that entity is functioning.[21]

5. Ancillary Services

Pinnacle requests authority to engage in the sale of certain ancillary services at market-based rates into the California ISO market.[22] Arizona Districts argue that the Pinnacle West Companies must first receive authority to make sales at market-based rates before selling ancillary services. Arizona Districts also argue that a market power study is required before sales of ancillary services at market-based rates can be made.

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[19]Arizona Districts Protest at 5.

[20]Arizona Districts' narrow interpretation of that requirement as applying for each inter-affiliate transaction only "with respect to a specific power sales agreement filed under a section 205 application between affiliates" (id. at 9) is in error.

[21]Pinnacle West Companies' Answer at 15.

[22]Pinnacle requests authority to provide the following ancillary services into the California ISO at market-based rates: Regulation and Frequency Response Service, Energy Imbalance Service, Operating Reserve - Spinning Reserve Service, and Operating Reserve - Supplemental Reserve Service. See Pinnacle Application, Exhibit B (Proposed APS Market-Based Tariff at p.2).

We will grant Pinnacle's request to make sales of ancillary services into the California ISO market.[23] In addition, we note that, notwithstanding Arizona Districts' argument, the Commission allows an entity to request authority to make sales of ancillary services at market-based rates at the same time that it seeks market-based rate authority for sales of capacity and energy.

In addition, we will reject as misplaced Arizona Districts' argument that a market power study is required before Pinnacle makes sales of ancillary services at market-based rates, as proposed in its application. There is no requirement for such market studies because the Commission has already authorized sales into the California ISO by all market-based rate sellers.

6. Reassignment of Transmission Capacity

Pinnacle states that, consistent with the conditions established by the Commission for reassignment of transmission capacity,[24] it will reassign transmission capacity at a price not to exceed the highest of: (1) the original rate paid by Pinnacle; (2) the applicable transmission provider's maximum rate on file at the time of the sale to the eligible customer; or (3) Pinnacle's own opportunity costs, capped at the applicable transmission provider's cost of expansion at the time of the Pinnacle sale to the eligible customer. Pinnacle's proposed tariff states that Pinnacle will not recover opportunity costs without making a separate filing under section 205 of the FPA. Finally, Pinnacle's tariff states that, when Pinnacle reassigns capacity that it has acquired for its own use on the transmission provider's open access system, all non-rate terms and conditions of the applicable tariff that otherwise would apply to a direct sale of transmission service (such as posting of discounts and disclosure of information) will continue to apply. We find Pinnacle's request to be consistent with our requirements applicable to the reassignment of transmission capacity and we accept Pinnacle's proposal.

B. Waivers, Authorizations and Reporting Requirements

Pinnacle requests the following waivers and authorizations: (1) waiver of the accounting and related reporting requirements of Parts 41, 101 and 141 of the

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[23]See AES Redondo Beach, L.L.C., et al., 85 FERC ¶ 61,123 (1998), order on reh'g, 87 FERC ¶ 61,208 (1999).

[24]See Order No. 888, FERC Stats. & Regs. at 31,694-97; Order No. 888-A, FERC Stats. & Regs. at 30,219-25; Commonwealth Edison Company, 78 FERC ¶ 61,312 at 62,335-36 (1997).

Commission's regulations; (2) permission to make abbreviated filings with respect to interlocking directorates under Part 45; (3) waiver of the requirements of Subparts B and C of Part 35, except sections 35.12(a), 35.13(b), 35.15 and 35.16; and (4) blanket approval of issuances of securities or assumptions of liabilities pursuant to Part 34 of the Commission's regulations. We will grant the requested waivers and authorizations consistent with those granted to other entities with market-based rate authorization.

Consistent with procedures we have adopted in other cases, Pinnacle may file umbrella service agreements for short-term power sales (one year or less) within 30 days of the date of commencement of short-term service, to be followed by quarterly transaction summaries of specific sales. For long-term transactions (longer than one year), Pinnacle must submit the actual individual service agreement for each transaction within 30 days of the date of commencement of service.[25] Pinnacle commits to make such filings in its application.[26]

Additionally, we will direct Pinnacle to inform the Commission promptly of any change in status that would reflect a departure from the characteristics the Commission has relied upon in approving market-based pricing. These characteristics include, but are not limited to: (1) ownership of generating or transmission facilities or inputs to electric power production other than fuel supplies; (2) affiliation with any entity not disclosed in the filing that owns generation or transmission facilities or inputs to electric power production; or (3) affiliation with any entity that has a franchised service area.[27]

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[25]On May 27, 1999, the Commission issued an order in which it modified the reporting requirements for long-term transactions applicable to public utilities without ownership or control over generation or transmission facilities that are authorized to sell power at market-based rates (power marketers). Southern Company Services, et al., 87 FERC ¶ 61,214 (1999), reh'g pending (Southern). Specifically, with respect to any long-term transaction agreed to by a power marketer after 30 days from the date of issuance of a final order in the Southern case, the power marketer must file a service agreement with the Commission within 30 days after service commences, rather than reporting transactions thereunder in its quarterly transaction summaries.

[26]See Pinnacle Application at 18.

[27]See, e.g., Morgan Stanley, 69 FERC ¶ 61,696 (1994), order on reh'g, 72 FERC ¶ 61,082 (1995); InterCoast Power Marketing Company, 68 FERC ¶ 61,248 at 62,134, clarified, 68 FERC ¶ 61,324 (1994).

Alternatively, Pinnacle may elect to report such changes in the updated market analysis it will be required to file every three years.[28]

Effective Date

We will conditionally accept for filing, the proposed market-based rate tariff and code of conduct of Pinnacle and the updated market-based rate tariffs and codes of conduct of APS and APSES, to become effective on June 20, 2000.

The Commission orders:

(A) Pinnacle's filings on behalf of Pinnacle West Companies are hereby conditionally accepted for filing, as discussed in the body of this order, to become effective on June 20, 2000.

(B) Pinnacle is hereby directed to file a compliance filing consistent with the discussion in the body of this order within 30 days of the date of this order.

(C) Pinnacle's request for waiver of Parts 41, 101 and 141 of the Commission's regulations is hereby granted, as discussed in the body of this order.

(D) Within 30 days of the date of issuance of this order, any person desiring to be heard or to protest the Commission's blanket approval of issuances of securities or assumptions of liabilities by Pinnacle should file a motion to intervene or protest with the Federal Energy Regulatory Commission, 888 First Street, NE, Washington, D.C. 20426, in accordance with Rules 211 and 214 of the Commission's Rules of Practice and Procedure, 18 C.F.R. §§ 385.211 and 385.214.

(E) Absent a request to be heard within the period set forth in Ordering Paragraph D above, Pinnacle is hereby authorized to issue securities and assume obligations or liabilities as guarantor, indorser, surety, or otherwise in respect of any security of another person; provided that such issue or assumption is for some lawful object within the corporate purposes of Pinnacle, compatible with the public interest, and reasonably necessary or appropriate for such purposes.

(F) Until further order of this Commission, the full requirements of Part 45 of the Commission's regulations, except as noted below, are hereby waived with respect to any person now holding or who may hold an otherwise proscribed interlocking directorate

[28]We reserve the right to require such an analysis at any time.

involving Pinnacle. Any such person instead shall file a sworn application providing the following information:

(1) full name and business address; and

(2) all jurisdictional interlocks, identifying the affected companies and the positions held by that person.

(G) The Commission reserves the right to modify this order to require a further showing that neither the public nor private interests will be adversely affected by continued Commission approval of Pinnacle's issuances of securities or assumptions of liabilities, or by the continued holding of any affected interlocks.

(H) Pinnacle's request for waiver of the provisions of Subparts B and C of Part 35 of the Commission's regulations, is hereby granted, with the exception of sections 35.12(a), 35.13(b), 35.15 and 35.16.

(I) Pinnacle may file umbrella service agreements for short-term power sales (one year or less) within 30 days of the date of commencement of short-term service, to be followed by quarterly transaction summaries of specific sales (including risk management transactions if they result in actual delivery of electricity). For long-term transactions (longer than one year), Pinnacle must submit the actual individual service agreement for each transaction within 30 days of the date of commencement of service.

(J) Pinnacle is hereby directed to file an updated market analysis within three years of the date of this order and every three years thereafter.

(K) Pinnacle is hereby directed to inform the Commission of any change in status that would reflect a departure from the characteristics the Commission has relied upon in approving market-based pricing.

(L) Pinnacle, APS, and APSE are hereby informed of the rate schedule designations found in Attachment A.

By the Commission.

(S E A L)

David P. Boergers,
Secretary.

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FILED
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FEDERAL ENERGY
REGULATORY COMMISSION

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Pinnacle West Capital Corporation	)	**Docket No. ER00-____-000**
	)	
Arizona Public Service Company	)	**Docket No. ER99-4124-000**
	)	
APS Energy Services Company, Inc.	)	**Docket No. ER99-4122-000**

APPLICATION OF PINNACLE WEST CAPITAL CORPORATION FOR ORDER APPROVING MARKET-BASED RATES, WAIVING REGULATIONS, AND GRANTING BLANKET APPROVALS; AND REQUEST OF ARIZONA PUBLIC SERVICE COMPANY AND APS ENERGY SERVICES COMPANY FOR MODIFICATION OF TARIFFS, CODES OF CONDUCT AND APS RATE SCHEDULES AND SERVICE AGREEMENTS

Pursuant to Section 205 of the Federal Power Act, 16 U.S.C. § 824d, and Rule 205 of the Rules of Practice and Procedure of the Federal Energy Regulatory Commission ("FERC" or the "Commission"), 18 C.F.R. § 385.205 (1999), Pinnacle West Capital Corporation ("PWCC") submits for filing this application for authorization to engage in wholesale power sales at market-determined prices. PWCC requests that the Commission accept its Market-Based Rate Tariff (the "Market Rate Tariff") for wholesale sales of energy and capacity, market-rate sales of ancillary services within the California Independent System Operator ("ISO") market, and the reassignment of transmission capacity.

PWCC also joins with its affiliates, Arizona Public Service Company ("APS") and APS Energy Services Company, Inc. ("APSES") (collectively, the "Pinnacle West Companies") in requesting that the Commission permit the Pinnacle West Companies to engage in inter-affiliate transactions at market-based rates and that the Commission find that, in view of the circumstances presented and commitments proposed herein, modifications to their wholesale codes of conduct are warranted. Specifically, retail

customers are protected from potential affiliate abuse through retail rate reduction obligations that APS has entered into with the Arizona Corporation Commission and/or the ability of such customers to choose their electric supplier. With regard to the limited number of wholesale customers potentially affected by transactions between and among the Pinnacle West Companies, the Pinnacle West Companies have fashioned additional commitments that will protect any such customer from potentially abusive inter-affiliate transactions. The proposed commitments, explained in more detail below, effectively cap relevant energy price components based upon competitive regional hub prices or, where applicable, upon historical fuel clause calculations.

PWCC also requests the Commission to grant standard waivers of certain of its regulations and to grant blanket authorizations of other actions under the Commission's regulations, in accordance with its policies with regard to entities engaged in power marketing activities.

Pursuant to § 35.3(a) of the Commission's regulations, PWCC requests an effective date for its Market-Based Rate Tariff of 60 days after the date of this filing, or the date on which the Commission issues an order approving the Tariff, whichever is earlier. APS and APSES request the same effective date for conforming modifications to their tariffs and codes of conduct.

I. BACKGROUND AND DESCRIPTION OF THE PARTIES

In this petition PWCC seeks authorization to engage in wholesale power marketing activities at negotiated market-based rates under the proposed Market-Based Rate Tariff. PWCC is an Arizona corporation whose principal place of business is located at 400 North 5th Street, Phoenix, Arizona. PWCC is a holding company that is exempt from registration under the Public Utility Holding Company Act of 1935, in accordance with Securities and Exchange Commission ("SEC") Rule 2(a)(1).[1] PWCC

[1] 17 C.F.R. § 250.2 (1999); *see* SEC File No. 69-306.

owns APS, a public service corporation organized under the laws of the State of Arizona, which is engaged in the business of generating, transmitting and distributing electricity in all or part of eleven of Arizona's fifteen counties. APS is authorized to sell wholesale power and energy at market-based rates.[2] In its order granting market-based rate authority to APS, the Commission found that APS does not possess market power.[3]

PWCC is also the parent of APSES, a retail marketer of electricity and energy-related services to customers in Arizona and California. APSES also engages in wholesale marketing and brokering of electricity that is largely incidental to its retail function. In a Letter Order dated October 13, 1999,[4] the Acting Secretary of the Commission, pursuant to delegated authority, accepted APSES's market-based rate schedule for filing. In doing so, the Secretary implicitly reaffirmed the Commission's earlier determination that APS and its affiliates do not possess market power in the relevant generation or transmission markets. Due to the creation of APSES, both APS and APSES submitted wholesale codes of conduct in accordance with Commission requirements.

At present, PWCC has no other electric utility subsidiaries (as the term "electric utility" is defined in Section 3(22) of the Federal Power Act[5]); however, PWCC owns Pinnacle West Energy Corporation ("PWEC"), a recently formed company to be engaged in the business of owning and operating exempt wholesale generating facilities. PWEC is currently engaged in developing and/or acquiring generation facilities in Arizona and elsewhere. It currently has no operating generating facilities and has no facilities subject

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2 *Arizona Public Service Co.*, 79 FERC ¶ 61,022 (1997). APS recently filed an updated market analysis in connection with its market-based rates. *Arizona Public Service Company*, Docket No. ER00-1875-000 (March 14, 2000).

3 79 FERC at 61,098-99.

4 Reported at 89 FERC ¶ 61,024.

5 16 U.S.C. § 796(22).

Additionally, PWCC has formed PWEC, which has filed for and obtained Certificates of Environmental Compatibility with the Arizona Power Plant and Transmission Line Siting Committee for two planned power plant projects.

Pursuant to the ACC approved Settlement Agreement, APS is required to divest generation assets by December 31, 2002.[11] It is anticipated that APS will divest its generation to PWEC. At that time, APS will become primarily a wires company.

In order to realize the full benefits of retail electric restructuring, as anticipated in the Arizona rules and the Agreement,[12] the competitive wholesale marketing and trading functions of APS will also be transferred to an affiliate of APS. The planned transfer of those functions to PWCC prompts the instant filing.

Finally, the Settlement Agreement also provides for an ACC Code of Conduct to govern the relationship between APS and APSES. This detailed and comprehensive retail code of conduct was recently approved by the ACC.[13]

II. COMMUNICATIONS

The Pinnacle West Companies respectfully request that service of pleadings and deliveries of communications and correspondence concerning this matter be directed to the following:

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[11] *See* ACC approved Settlement Agreement, § 4.1.

[12] *See, e.g.*, ACC Rule R14-2-1615, titled "Separation of Monopoly and Competitive Services;" ACC approved Settlement Agreement, § 4.2.

[13] Decision No. 61973.

David A. Hansen, Director
Bulk Power Marketing and Trading
Arizona Public Service Company
400 North 5th Street
Mail Station 9842
Phoenix, Arizona 85004
Phone: (602) 250-2327

Barbara Muller Champion
Senior Attorney
Pinnacle West Capital Corporation
400 North 5th Street
Mail Station 8695
Phoenix, Arizona 85004
Phone: (602) 250-3547

Joel R. Spitzkoff
Manager of Federal Regulation
Arizona Public Service Company
400 North 5th Street
Mail Station 9905
Phoenix, Arizona 85004
Phone: (602) 250-2949

Vicki G. Sandler
Vice President
APS Energy Services Company, Inc.
400 East Van Buren Street
Suite 750
Phoenix, Arizona 85004
Phone: (602) 744-5045

John D. McGrane
Mary Ann K. Huntington
Alex M. Schnell
Morgan, Lewis & Bockius LLP
1800 M Street, N.W.
Washington, D.C. 20036
Phone: (202) 467-7621

Applicants request that the above-listed individuals be placed on the official service list compiled for this proceeding.

III. LIST OF MATERIALS SUBMITTED WITH THIS FILING

This filing contains the following materials:

1. Exhibit A – PWCC's Market-Rate Tariff, including a form of service agreement and a Code of Conduct;

2. Exhibit B – conformed copy and redlined copy of APS's Market-Based Rate Tariff and modified Code of Conduct, indicating proposed changes;

3. Exhibit C – conformed copy and redlined copy of APSES's Market-Based Rate Tariff and modified Code of Conduct, indicating proposed changes;

4. Exhibit D – conformed and redlined copies of the proposed supplements to APS's wholesale contracts, tariffs and rate schedules that include system incremental cost ("SIC") provisions; attached to each supplement is a table with a sample derivation of the Palo Verde Shaped Index;

associated ancillary services acquired for its own use under open access transmission tariffs. The Market Rate Tariff permits PWCC to resell such capacity and rights at a price not higher than the highest of (1) the price PWCC originally paid for the service, (2) the transmission provider's maximum rate for the service on file at the time of the resale, or (3) PWCC's own opportunity costs capped at the applicable transmission provider's cost of expansion at the time of the sale to the eligible customer.[17] The resold service will be provided in accordance with the terms and conditions of service of the original transmission provider's applicable open access transmission tariff. PWCC's proposed reassignment of transmission and associated ancillary services is wholly consistent with reassignment provisions the Commission previously has accepted.[18]

A. Market Power

With respect to its market power concerns, the Commission generally requires that an entity seeking authorization to transact at market-based rates (1) demonstrate that the entire output of its or any of its affiliates' generating facilities is committed under long-term contracts, (2) demonstrate that the applicant or its affiliates already are authorized to sell power at market-based rates, or (3) submit a market analysis that indicates that neither the applicant nor its affiliates have generation dominance in the relevant markets.[19]

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[17] PWCC will not charge a rate based on its opportunity costs absent a separate filing under Section 205 of the Federal Power Act.

[18] *See, e.g., Alliant Services Company*, 85 FERC ¶ 61,344 (1998); *Select Energy, Inc.*, 85 FERC ¶ 61,290 (1998); *Commonwealth Edison Co.*, 78 FERC ¶ 61,312 (1997).

[19] *LG&E Power Marketing, Inc.*, 68 FERC ¶ 61,247, at 62,121 (1994).

PWCC's affiliates APS and APSES are already authorized to sell power at market-based rates.[20] PWCC relies on the market power study that its affiliates relied upon in support of their market-based rate applications, consistent with FERC precedent.[21] Moreover, because PWCC does not directly own or control any generating facilities (other than its ultimate ownership of APS), PWCC has no market power in generation. As such, the Commission should reach the same conclusion here that it reached in *Arizona Public Service Co.* -- that PWCC does not have generation market power.[22]

B. Transmission Market Power

In order to ensure that applicants for market-based rate authority do not possess transmission market power, the Commission generally requires the applicant, or its affiliated public utility, to file or have on file open access transmission tariffs for the provision of comparable services.[23] APS filed its open access tariff on July 9, 1996 (Docket No. OA96-153-000), and a revised open access tariff on July 12, 1996 (Docket No. ER96-2401-000). The Commission consolidated the two dockets and, on June 18,

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20 *See Arizona Public Service Co.*, 79 FERC at 61,098-101; *APS Energy Services*, Letter Order, 89 FERC ¶ 61,024.

21 *See, e.g., Alliant Services Co.*, 85 FERC ¶ 61,344 (finding no market power based on affiliates' market study approved in earlier merger order); *Louisville Gas and Electric Co., et al.*, 85 FERC ¶ 61,215 (1998) (finding no market power based on affiliates' market studies approved in earlier market-based rate application orders).

22 As explained in footnote 2, above, APS recently filed an update to its market power study. *See Arizona Public Service Co.*, Docket No. ER00-1875-000.

23 *See, e.g., Southern Indiana Gas & Electric Company*, 77 FERC ¶ 61,021 (1996).

1999, issued a letter order accepting a settlement governing APS's transmission rates in the consolidated dockets.

PWCC does not own any transmission facilities (other than through its ownership of APS). Accordingly, the availability of open access transmission service over APS's transmission facilities under the APS transmission tariff eliminates the potential for any exercise of transmission market power by PWCC.

C. Barriers to Entry

In previous cases, the Commission has examined the possibility that an entity might be able to erect other barriers to entry as a possible ground for denying the authority to charge market-based rates.[24] PWCC, APS and APSES are not affiliated with entities that could impose barriers to entry in the electric power generation business through their ownership or control of any resources or inputs that could be essential to market entry by competitors.

D. Affiliate Abuse and Reciprocal Dealing

In evaluating market-based rate applications of affiliated power marketers, the Commission considers the potential for affiliate abuse and reciprocal dealing. The Commission has explained that affiliate abuse takes place when a public utility and an affiliated power marketer transact in ways that result in a transfer of benefits from the public utility (and the ratepayers) to the power marketer (and the shareholders).[25] Here, due to the restructuring of the Arizona retail market and the commitments made with

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[24] *Heartland*, 68 FERC at 62,062.

[25] *Id.*; *Wholesale Power Services, Inc.*, 72 FERC ¶ 61,284 (1995).

respect to APS's wholesale customers, there is no potential for affiliate abuse. Accordingly, the Commission should permit the Pinnacle West Companies to engage in transactions at negotiated market-based prices with each other and modify certain requirements of the codes of conduct governing relations between the Pinnacle West Companies.

The Pinnacle West Companies do not seek to eliminate all the code of conduct requirements. Although, as demonstrated below, there is no risk to APS's customers from inter-affiliate transactions and relationships under the circumstances presented (and therefore no need for any code of conduct limitations), the Pinnacle West Companies do not propose to modify or eliminate at this time the code of conduct provisions which ensure that transactions among the affiliates are properly accounted for. The Pinnacle West Companies only seek to eliminate those wholesale code of conduct provisions that limit or condition the transfer of information among the Pinnacle West Companies. The proposed PWCC code of conduct and the modified codes of conduct for APS and APSES are attached as part of Exhibits A - C. The Pinnacle West Companies note that the ACC code of conduct will also continue to govern relationships between APS and APSES.

As detailed below, there is no risk of harm to APS's retail or wholesale customers from the proposed changes to the codes of conduct. APS's wholesale customers are protected by putting in place measures that will prevent any potentially inappropriate costs associated with affiliated transactions from being passed through to these customers. Under the Arizona restructuring and the Settlement Agreement, APS's retail

customers are protected by what is in essence a rate reduction and freeze and/or their ability to choose their electric supplier.[26]

1. APS's Retail Customers are Protected.

In *Enron Energy Services Power, Inc.*, the Commission held that where a public utility's retail customers have a choice of alternative suppliers, there is no potential for affiliate abuse.[27] Retail restructuring is in the process of being implemented in Arizona, and a substantial portion of APS's retail customers are already authorized to choose their generation provider.[28] APS's retail customers that are not already entitled to choose their electric service provider are provided rate reductions that will remain in effect until 2004, well after full retail choice is implemented in 2001.[29] Although APS has a right to propose rate changes for emergencies or specified extraordinary events during this period, for all practical purposes retail rates are frozen at the reduced levels.[30] The Commission has recognized that affiliate transactions cannot harm customers protected by a rate freeze.[31]

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[26] *See AmerGen Energy Co., L.L.C.*, 90 FERC ¶ 61,080 (2000) (ratepayers who have retail choice or are protected by a rate freeze are not captive customers); *Green Power Partners I, LLC, et al.*, 88 FERC ¶ 61,005 (1999) (waiving code of conduct requirement for UGI Development Co. because UGI does not have captive customers); *Enron Energy Services Power, Inc.*, 81 FERC ¶ 61,267 (1997) ("we will not accept PECO's request that we treat customers participating in a state retail [choice] program as captive customers requiring expansion of Enron Energy's code of conduct").

[27] 81 FERC ¶ 61,267 (1997); *see AmerGen Energy Co., L.L.C.*, 90 FERC ¶ 61,080 (2000).

[28] *See* ACC approved Settlement Agreement, § 1.1.

[29] *See* ACC approved Settlement Agreement, §§ 2.2, 2.6, 2.7.

[30] To the extent such an emergency or extraordinary event occurs and APS determines to file for increased retail rates, it will notify the Commission at that time.

[31] *Illinova Power Marketing, Inc., et al.*, 88 FERC ¶ 61,189 (1999) (revisions to inadequate code of conduct unnecessary because Illinois Power's retail customers are already protected by a rate freeze); *AYP Energy, Inc.*, 87 FERC ¶ 61,009 (1999); *Commonwealth Edison Co.*, 85 FERC ¶ 61,288 (1998).

Where there is no potential for affiliate abuse, there is no need for the Commission to require the full panoply of code of conduct rules it normally requires as a condition of granting market-based rate authority.[32]

2. The Pinnacle West Companies' Mitigation Proposals Will Prevent Cost Shifting to APS's Wholesale Customers.

The Pinnacle West Companies have identified two limited areas of concern in APS's existing wholesale power contracts where there may be the potential for affiliated entities to shift costs to certain contractually obligated wholesale customers. The Pinnacle West Companies propose to mitigate any potential harm to wholesale customers by putting in place measures that will protect the customers from the improper pass-through of costs associated with affiliated transactions.

The Commission has recognized that an effective method of mitigating affiliate abuse concerns is capping the pass through of costs to wholesale customers at prices set by a competitive regional market hub.[33] Benefits resulting from the use of regional market hubs extend beyond the mere mitigation of potential abusive inter-affiliate transactions by the Pinnacle West Companies. Using regional hub indices as an alternative to requiring a code of conduct to prevent inter-affiliate abuse will provide secondary benefits including: a positive incentive for utilities to create, join and transact

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[32] *See AmerGen Energy Co., L.L.C.*, 90 FERC ¶ 61,080; *Green Power Partners I, LLC, et al.*, 88 FERC ¶ 61,005 (1999) (waiving code of conduct requirement for UGI Development Co. because UGI does not have captive customers); *Enron Energy Services Power, Inc.*, 81 FERC ¶ 61,267 at 62,318 (1997) ("we will not accept PECO's request that we treat customers participating in a state retail [choice] program as captive customers requiring expansion of Enron Energy's code of conduct").

[33] *See FirstEnergy Trading Services, Inc.*, 88 FERC ¶ 61,067 (1999); *AYP Energy, Inc.*, 87 FERC ¶ 61,009 (1999); *FirstEnergy Trading & Power Marketing, Inc.*, 84 FERC ¶ 61,214 (1998).

their business through regional market hubs; greater transparency in pricing of power transactions (because the hub price is a published price); and reducing Commission staff time spent reviewing affiliate transactions through the use of objective, market-based determinants for passing through costs.

The Pinnacle West Companies' proposed system incremental cost mitigation measure makes use of regional hubs to mitigate the potential for affiliate abuse and are explained in detail below. The Pinnacle West Companies also propose a mechanism for dealing with costs flowing through the wholesale fuel adjustment clause, by capping the pass through at a historical average.

a. System Incremental Cost Provisions

The first potential area of concern applies to wholesale contracts that include a pricing provision based upon APS's system incremental cost ("SIC"). If a transaction between APS and an affiliate is used in establishing the energy price for a particular hour, then it could increase the prices paid by APS's wholesale customers that take service under these contracts. The SIC provision in some of APS's wholesale contracts presents the potential to harm wholesale customers if an affiliated transaction establishes APS's incremental cost for a particular hour.

The Pinnacle West Companies propose to mitigate this concern by capping the portion of these customers rates that include a SIC component at the lesser of: (i) the monthly rates calculated utilizing APS's actual hourly SIC values (the existing methodology); or (ii) the monthly rates calculated utilizing an hourly cents per kWh market index in lieu of the actual SIC. The market index is derived based on prices at Palo Verde, a liquid market hub that reflects market prices for the region. Because the

Palo Verde hub only publishes on-peak and off-peak, day-ahead prices, while the applicable SIC contract provisions are based upon APS's hourly SIC, APS proposes to utilize the hourly price indices published by the California PX for the nearby SP15 zone to "shape" the daily prices at Palo Verde into an hourly price curve. The resulting index, that will be used to protect SIC wholesale customers, is referred to as the Palo Verde Shaped Index.[34]

Exhibit D to this Application contains SIC customer contracts modified to reflect the use of the Palo Verde Shaped Index to mitigate market power concerns. Table A, attached to each of the modified wholesale customer SIC contracts included in Exhibit D, provides an example of how the Palo Verde Shaped Index will work in practice.

Once the Palo Verde Shaped Index has been derived for each hour of each day of a particular billing month, APS will then compare the monthly charge that each SIC customer would pay under the Palo Verde Shaped Index to the actual charges APS incurred, based upon its SIC methodology, for the entire month. APS will bill the SIC customer based upon the lower of the two total monthly charges (SIC or Palo Verde Shaped Index) for the relevant billing month.

By applying the lesser of SIC or the Palo Verde Shaped Index cost, wholesale customers are protected from affiliate abuse and receive the additional benefit of potential reduced power costs based on the hub prices. The Commission has recognized on numerous occasions that tying prices charged to an established and relevant market index

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[34] Should a robust hourly market develop at Palo Verde, APS will file a request to convert from the Palo Verde Shaped Index to the use of actual Palo Verde hourly market prices.

adequately mitigates affiliate abuse concerns.[35] Both the Palo Verde hub and the California PX zone used for shaping the Palo Verde daily prices are active trading locations with published prices.

By employing a price cap based on competitive market hub prices in the region in which APS operates its system, the Pinnacle West Companies have proposed a win-win-win-win situation. Customers are protected from any potential for affiliate abuse because the alternative system incremental cost is based on a market index that will not be materially affected by transactions among the Pinnacle West Companies. The Pinnacle West Companies benefit because they will be able to transact under the new structure envisioned by the Arizona restructuring rules in much the same way as they currently operate within APS and in the same manner as other market participants in Arizona transact with their affiliates. Participants in the regional markets also "win," because relying upon the Palo Verde hub market price recognizes the legitimacy and value of regional markets. The final "winner" is the Commission, which will be able to rely more upon objective market prices to protect customers.

b. Fuel Adjustment Clauses

The second potential area of concern relates to APS's wholesale contracts that include a fuel adjustment clause ("FAC") which flows through certain fuel and purchased

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[35] *Allegheny Energy Supply Co.*, 88 FERC ¶ 61,303 (1999) ("tying the price of an affiliate transaction . . . to an established, relevant market price adequately mitigates any affiliate abuse concerns"); *First Energy Trading Services, Inc.*, 88 FERC ¶ 61,067 (1999); *AYP Energy, Inc.*, 87 FERC ¶ 61,009 (1999).

power costs to some APS wholesale customers.[36] Due to the limited nature of APS's wholesale FAC power sales[37] (and APS's concomitant limited ability and incentive to engage in abusive conduct) the burden of tying FAC calculations to market prices where purchased power is at issue does not appear to be warranted. However, in order to mitigate even the remote possibility of harm to APS's FAC customers, APS proposes to cap the monthly expense of fossil and nuclear fuel and the net energy cost of certain power purchases[38] at the lesser of actual cost, or historical cost based upon an average of 1998 and 1999 fuel and eligible purchased power costs for the relevant monthly period. APS's FAC costs in these years should provide a reasonable cap for these contracts; APS's wholesale FAC customers will receive the benefit of actual FAC costs if they are lower than the applicable monthly average from 1998-1999 , but will be protected from the FAC pass-through of costs that exceed the proposed cap. Modified customer contracts and a sample re-calculation based on 1998-1999 fuel costs are included as Exhibits E1 and E2 to this Application.

E. The Commission's Filing Requirements

Consistent with the Commission's requirements, PWCC commits that it will file quarterly transaction summaries and satisfy the Commission's other standard reporting

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[36] Proposed modifications to APS's FACs are included as Exhibits E1 and E2 to this Application.

[37] APS sold 198 GWH of energy to wholesale customers with FAC contracts in 1999, with total energy-related revenues of $4.2 million. APS's overall energy sales were 36,768 GWH and its total electric revenues were $2,292 million. Thus, APS made less than 0.5% of its total kWh sales to FAC customers in 1999.

[38] Power purchases used in calculating the "F" component of the fuel cost adjustment factor.

requirements for affiliated power marketers.[39] Specifically, PWCC will file umbrella service agreements for short-term transactions (one year or less) within 30 days of the date of commencement of service, to be followed by quarterly transaction summaries for specific sales. For long-term transactions (longer than one year), the actual service agreement for each transaction will be filed within 30 days after commencement of service.[40]

PWCC commits that it will file a revised market power analysis every three years.[41]

V. REQUEST FOR MODIFICATION OF APS AND APSES TARIFFS, CODES OF CONDUCT, AND RATE SCHEDULES AND SERVICE AGREEMENTS.

APS and APSES have market rate tariffs and codes of conduct on file with the Commission. As noted above, the Pinnacle West Companies, including APS and APSES have no captive retail customers and have mitigated potential concerns with certain wholesale customers by effectively capping relevant energy price components based upon competitive regional hub prices, or where applicable, upon historic fuel clause calculations. APS and APSES therefore request that the Commission: (1) find that each of these entities have adequately mitigated any potential for affiliate abuse; (2) accept for filing the revised market-based rate tariffs included as Exhibits B and C hereto that permit

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[39] *See Southern Co. Services, Inc.*, 87 FERC ¶ 61,214 (1999); *Horizon Energy Co.*, 81 FERC ¶ 61,368 (1997).

[40] *Southern Co. Services, Inc.*, 87 FERC at 61,848-49.

[41] *See Morgan Stanley Capital Group, Inc.*, 69 FERC ¶ 61,175 (1994) (as clarified in *Engelhard Power Marketing, Inc.*, 70 FERC ¶ 61,250 (1995)).

sales to affiliates; and (3) permit APS and APSES to modify their existing codes of conduct as discussed above and as set forth in Exhibits B and C.

In furtherance of its commitments to wholesale customers, APS also submits revised sheets to the rate schedules and service agreements reflecting APS's commitment to tie SIC and FAC clauses included in its contracts to regional hub prices or historical costs, as appropriate. The revised rate schedules and service agreements are included in Exhibits D and E to this Application. APS requests that the Commission accept these revised sheets for filing.

VI. REQUEST FOR EFFECTIVE DATE AND WAIVERS

Consistent with the Commission's decisions in previous power marketer cases, PWCC respectfully requests that the Commission waive the following requirements of the Commission's regulations: (1) the accounting and reporting requirements under Parts 41, 101, and 141 of the Commission's regulations; (2) the interlocking directorate filing requirements under Part 45 of the Commission's regulations, or, alternatively, permission to file abbreviated filings with respect to interlocking directorates under Part 45; (3) the filing requirements of Subparts B and C of Part 35 of the Commission's regulations, other than Sections 35.12(a), 35.13(b), 35.15 and 35.16; and (4) blanket authorization under Part 34 of all future issuances of securities and assumptions of obligations or liabilities as guarantor, endorser, surety or otherwise in respect of any security of any person.[42] Pursuant to Section 35.3(a) of the Commission's regulations, PWCC respectfully requests that the Commission accept the Market Rate Tariff for filing and

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[42] *See, e.g., AES Huntington Beach, L.L.C.*, 83 FERC ¶ 61,100 (1998).

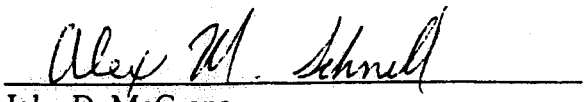
permit it to become effective the earlier of either sixty days after the date of this filing or the date upon which the Commission grants acceptance.

VII. CONCLUSION

The Pinnacle West Companies request that the Commission issue an order granting: (1) authorization for PWCC to engage in wholesale sales of electric power at market-based rates, including market-rate sales to its affiliates and sales of ancillary services at market-based rates in the California market; (2) acceptance of PWCC's request for permission to reassign transmission capacity; (3) acceptance of the PWCC Market Rate Tariff for filing effective the earlier of sixty days after the filing of this application or upon issuance of an order accepting the Tariff for filing; (4) acceptance of the proposed modifications to the code of conduct requirements applicable to the Pinnacle West Companies, conditioned on the commitments proposed herein; (5) acceptance of the revised APS and APSES market-based rate tariffs included as Exhibits B and C hereto, (6) acceptance for filing of the revised wholesale rate schedules and service agreements

included in Exhibits D and E hereto; (7) certain blanket authorizations; and (8) certain waivers of the Commission's regulations as requested herein.

Respectfully submitted,



John D. McGrane
Mary Ann K. Huntington
Alex M. Schnell
Morgan, Lewis & Bockius LLP
1800 M Street, N.W.
Washington, D.C. 20036
Phone: (202) 467-7000

Barbara Muller Champion, Senior Attorney
Pinnacle West Capital Corporation
P.O. Box 53999
Mail Station 8695
Phoenix, Arizona 85072-3999
Phone: (602) 250-3547

Attorneys for
Pinnacle West Capital Corporation

Dated: April 21, 2000

Exhibit A

Pinnacle West Capital Corporation

Market-Based Rate Tariff

and

Code of Conduct

Pinnacle West Capital Corporation

MARKET-BASED RATE TARIFF

1. Availability: Pinnacle West Capital Corporation ("PWCC") makes electric capacity or energy available for sale for resale under this Rate Schedule to any purchaser.

2. Applicability: This schedule is applicable to all sales of electric capacity or energy by PWCC not otherwise subject to a particular rate schedule of PWCC.

   This schedule is also available for purchases by the California Independent System Operator Corporation and its suppliers and market participants of Replacement Reserve Service and the following ancillary services as defined by the Commission: Regulation and Frequency Response Service, Energy Imbalance Service, Operating Reserve-Spinning Reserve Service, and Operating Reserve-Supplemental Reserve Service.

   This schedule also is applicable to the reassignment of transmission capacity, transmission rights and associated ancillary services, that PWCC has acquired for its own use on the transmission systems of transmission providers.

3. Rates: All sales of electric capacity or energy shall be made at rates established by agreement between the purchaser and PWCC.

4. Other Terms and Conditions:

   All other terms and conditions shall be established by agreement between the purchaser and PWCC.

5. Effective Date:

   This Rate Schedule shall be effective on the date established by FERC.

6. Reassignment of Transmission Rights:

PWCC may reassign transmission capacity, transmission rights, and associated ancillary services that it has reserved for its own use at a price not to exceed the highest of: (1) the original transmission rate paid by PWCC; (2) the applicable transmission provider's maximum stated firm transmission rate on file at the time of the transmission reassignment; or (3) PWCC's own opportunity costs, capped at the applicable transmission provider's cost of expansion at the time of the sale to the eligible customer. PWCC will not recover opportunity costs in connection with reassignment without making a separate filing under Section 205. Except for the price, the terms and conditions under which the reassignment is made shall be under the terms and conditions governing the original grant by the transmission provider. Transmission and associated ancillary services may only be reassigned to a customer eligible to take service under the transmission provider's open access transmission tariff or other transmission rate schedules. PWCC will report the name of the assignee in its quarterly reports.

Pinnacle West Capital Corporation

MARKET-BASED RATE TARIFF

SERVICE AGREEMENT

This Service Agreement, dated as of _____, is entered into by and between Pinnacle West Capital Corporation ("PWCC") and _____ ("Customer"), pursuant to PWCC's Market-Based Rate Tariff, FERC Electric Tariff No. 1 ("Tariff").

Each transaction hereunder will be carried out under terms and conditions as agreed upon by PWCC and the Customer in accordance with the terms and conditions of the Tariff.

IN WITNESS WHEREOF, PWCC and Customer have caused this Service Agreement to be executed by their respective authorized officials as of the date first above written.

Customer	**Pinnacle West Capital Corporation**
_____	
Customer	
_____	_____
Signature of Representative Date	Signature of Representative Date
_____	_____
Name of Representative	Name of Representative
_____	_____
Title of Representative	Title of Representative

Pinnacle West Capital Corporation

STATEMENT OF POLICY AND CODE OF CONDUCT WITH RESPECT TO THE RELATIONSHIP BETWEEN PINNACLE WEST CAPITAL CORPORATION AND ARIZONA PUBLIC SERVICE COMPANY

The following Code of Conduct will govern the relationship between Pinnacle West Capital Corporation ("PWCC") and any other marketing affiliates that may be authorized by the Federal Energy Regulatory Commission to engage in sales for resale of energy and capacity at market-based rates (the "Marketing Affiliates"), and Arizona Public Service Company ("APS").

Marketing of Power

1. To the maximum extent practical, the employees of the Marketing Affiliates will operate separately from the employees of APS.

2. Sales of any non-power goods or services by APS, including sales made through affiliated EWGs or QFs, to the Marketing Affiliates will be at the higher of cost or market price.

3. Sales of any non-power goods or services by the Marketing Affiliates to APS will not be at a price above market.

Brokering of Power

To the extent Marketing Affiliates seek to broker power for APS:

4. Marketing Affiliates will offer APS's power first.

5. The arrangement between Marketing Affiliates and APS is non-exclusive.

6. Marketing Affiliates will not accept any fees in conjunction with any brokering services they perform for APS.

ARIZONA PUBLIC SERVICE COMPANY
MARKET RATE TARIFF NO. 1
(MR-1)

1 DEFINITIONS

The following terms shall have the specified meaning when used in the Market Rate Tariff No. 1 ("Tariff") or in a Service Agreement:

1.1 **Commission:** The Federal Energy Regulatory Commission.

1.2 **Customer:** An entity that executes a Service Agreement under this Tariff.

1.3 **Service Agreement:** The initial agreement and any supplements thereto entered into by a Customer and Arizona Public Service Company ("APS") for service under this Tariff.

1.4 **Tariff:** This Market Rate Tariff No. 1 as it may be amended and/or superseded from time to time.

1.5 **Transaction:** An individual transaction scheduled pursuant to this Tariff and a Service Agreement.

1.6 **Party:** References to a Party shall mean either APS or the Customer, or collectively shall be referred to as "Parties."

2 AVAILABILITY

This Tariff is available for purchases of electric energy and/or capacity from APS. This Tariff is also available for purchases by the California Independent System Operator Corporation and its suppliers and market participants of Replacement Reserve Service and the following ancillary services as defined by the Commission: Regulation and

Frequency Response, Energy Imbalance, Operating Reserve - Spinning Reserve, and Operating Reserve - Supplemental Reserve.

3 CHARACTER OF SERVICE

APS may provide capacity and/or energy under this Tariff in varying amounts, at varying levels of firmness or priorities of service, for varying periods of service, and in accordance with varying delivery schedules, as agreed to between the Customer and APS. APS may also provide to the California Independent System Operator Corporation and its suppliers and market participants, at market based rates, Replacement Reserve Service and the following ancillary services as defined by the Commission: Regulation and Frequency Response, Energy Imbalance, Operating Reserve - Spinning Reserve, and Operating Reserve - Supplemental Reserve.

4 RATES

4.1 The rates for purchases under this Tariff shall be as agreed to by the Customer and APS.

4.2 Transmission and Ancillary Services:

4.2.1 When transmission and ancillary services to effectuate power sales transactions under APS' market-based tariff are to be obtained by APS, APS will file a service agreement placing itself under its open access transmission tariff.

4.2.2 When the customer itself is obtaining the transmission and ancillary services from APS on its own behalf, APS will file a service agreement placing the customer under its Open Access Transmission Tariff.

5 SERVICE AGREEMENTS

5.1 Prior to the commencement of service to a new customer, APS and each new Customer will execute a Service Agreement.

5.1.1 APS will file umbrella agreements for short-term transactions (one year or less) within 30 days of commencement of such service with the Commission. APS will file quarterly transaction summary reports of all short-term transactions under this Tariff stating separately the prices for generation, transmission, and ancillary services.

5.1.2 For long-term transactions (longer than one year), the separate prices for generation, transmission and ancillary services will be included as part of the Service Agreement to be filed with the Commission within 30 days of commencement of service.

5.2 APS may refuse, at its sole discretion, to enter into a Service Agreement or Transaction under this Tariff. APS is under no obligation to execute a Service Agreement to provide service hereunder.

5.3 Acceptance of service by the Customer pursuant to a Service Agreement commits the Customer to the provisions of this Tariff and to the terms of the Service Agreement.

6 EXPANSION OF FACILITIES

APS will have no obligation under this Tariff or any Service Agreement executed hereunder to plan its system, to enlarge or modify its facilities or operate its system in such a manner in order to provide or maintain energy and/or capacity sold hereunder.

7 REASSIGNMENT OF TRANSMISSION RIGHTS

APS may reassign transmission capacity, transmission rights, and associated ancillary services that it has reserved for its own use at a price not to exceed the highest of: (1) the original transmission rate paid by APS; (2) the applicable transmission provider's maximum stated firm transmission rate on file at the time of the transmission reassignment; or (3) APS' own opportunity costs, capped at the applicable transmission providers' cost of expansion at the time of the sale to the eligible customer. APS will not recover opportunity costs in connection with reassignment without making a separate filing under Section 205. Except for the price, the terms and conditions under which the reassignment is made shall be under the terms and conditions governing the original grant by the transmission provider. Transmission and associated ancillary services may only be reassigned to a customer eligible to take service under the transmission provider's open access transmission tariff or other transmission rate schedules. APS will report the name of the assignee in its quarterly reports.

8 REVISIONS TO TARIFF

APS may file revisions to this Tariff with the Commission. Nothing contained in this Tariff shall be construed as effecting or limiting in any way the right of APS to

unilaterally file with the Commission for a change in any aspect of this Tariff under Section 205 or 206 of the Federal Power Act pursuant to the Commission's Rules and Regulations promulgated thereunder.

9 EFFECTIVE DATE

This Tariff shall be effective on the date established by the Commission.

FORM OF SERVICE AGREEMENT

This Service Agreement, dated as of _____, is entered into by and between Arizona Public Service Company ("Company"), and _____ ("Customer"), pursuant to the Company's Market Rate Tariff No. 1 ("Tariff").

Each transaction hereunder shall be carried out under terms and conditions as agreed upon by the Company and Customer in accordance with the terms and conditions of the Tariff.

In the event the Customer requests that APS' Merchant Group secure on the Customer's behalf transmission services and ancillary services required to effect transactions of power and/or energy under this Tariff, the Customer shall designate below the transmission and ancillary services needed:

Network Integration Transmission Service: ❑

Firm Point-to-Point Transmission Service:

❑ Monthly ❑ Weekly ❑ Daily

Non-Firm Point-to-Point Service:

❑ On-Peak ❑ Off-Peak

Ancillary Services:

❑ Scheduling, System Control & Dispatch Service

❑ Reactive Supply & Voltage Control from Generation Sources Service

❑ Regulation & Frequency Response Service

❑ Energy Imbalance Service

❑ Operating Reserve - Spinning Reserve Service

❑ Operating Reserve - Supplemental Reserve Service

Customer shall incur no obligation by requesting that services be made available.

Accepted by FERC _____, 2000

IN WITNESS WHEREOF, Company and Customer have caused this Service Agreement to be executed by their respective authorized officials as of the date first above written.

ARIZONA PUBLIC SERVICE COMPANY

By: _____

Title: _____

Date: _____

_____
(Customer)

By: _____

Title: _____

Date: _____

Accepted by FERC _____, 2000

Arizona Public Service Company

STATEMENT OF POLICY AND CODE OF CONDUCT WITH RESPECT TO THE RELATIONSHIP BETWEEN ARIZONA PUBLIC SERVICE COMPANY AND IT'S MARKETING AFFILIATES

The following Code of Conduct will govern Arizona Public Service Company's ("APS'") relationship with APS Energy Services Company, Inc. ("APSES"), Pinnacle West Capital Corporation ("PWCC"), and any other marketing affiliates that may be authorized by the Federal Energy Regulatory Commission to engage in sales for resale of energy and capacity at market-based rates (the "Marketing Affiliates").

Marketing of Power

1. To the maximum extent practical, the employees of the Marketing Affiliates will operate separately from the employees of APS.

2. Sales of any non-power goods or services by APS, including sales made through affiliated EWGs or QFs, to the Marketing Affiliates will be at the higher of cost or market price.

3. Sales of any non-power goods or services by the Marketing Affiliates to APS will not be at a price above market.

Brokering of Power

1. To the extent APS brokers power sales for the Marketing Affiliates, APS will offer its own power first.

2. APS will charge its Marketing Affiliates the higher of APS' cost for brokering services or the market rate for such services. APS will post the actual brokering charges imposed.

ARIZONA PUBLIC SERVICE COMPANY
MARKET RATE TARIFF NO. 1
(MR-1)

1 DEFINITIONS

The following terms shall have the specified meaning when used in the Market Rate Tariff No. 1 ("Tariff") or in a Service Agreement:

1.1 **Commission:** The Federal Energy Regulatory Commission.

1.2 **Customer:** An entity that executes a Service Agreement under this Tariff.

1.3 **Service Agreement:** The initial agreement and any supplements thereto entered into by a Customer and Arizona Public Service Company ("APS") for service under this Tariff.

1.4 **Tariff:** This Market Rate Tariff No. 1 as it may be amended and/or superseded from time to time.

1.5 **Transaction:** An individual transaction scheduled pursuant to this Tariff and a Service Agreement.

1.6 **Party**: References to a Party shall mean either APS or the Customer, or collectively shall be referred to as "Parties."

2 AVAILABILITY

~~[2.1]~~ This Tariff is available for purchases of electric energy and/or capacity from APS. This Tariff is also available for purchases by the California Independent System Operator Corporation and its suppliers and market participants of Replacement Reserve Service and the following ancillary services as defined by the Commission: Regulation and Frequency Response, Energy Imbalance, Operating Reserve - Spinning Reserve, and Operating Reserve - Supplemental Reserve.

~~[2.2 No entity affiliated with APS is eligible for service under this Tariff.~~

3 CHARACTER OF SERVICE

APS may provide capacity and/or energy under this Tariff in varying amounts, at varying levels of firmness or priorities of service, for varying periods of service, and in accordance with varying delivery schedules, as agreed to between the Customer and APS. APS may also provide to the California Independent System Operator Corporation and its suppliers and market participants, at market based rates, Replacement Reserve Service and the following ancillary services as defined by the Commission: Regulation and Frequency Response, Energy Imbalance, Operating Reserve - Spinning Reserve, and Operating Reserve - Supplemental Reserve.

4 RATES

4.1 The rates for purchases under this Tariff shall be as agreed to by the Customer and APS.

4.2 Transmission and Ancillary Services:

4.2.1 When transmission and ancillary services to effectuate power sales transactions under APS' market-based tariff are to be obtained by APS, APS will file a service agreement placing itself under its open access transmission tariff.

4.2.2 When the customer itself is obtaining the transmission and ancillary services from APS on its own behalf, APS will file a service agreement placing the customer under its Open Access Transmission Tariff.

5 SERVICE AGREEMENTS

5.1 Prior to the commencement of service to a new customer, APS and each new Customer will execute a Service Agreement.

5.1.1 APS will file umbrella agreements for short-term transactions (one year or less) within 30 days of commencement of such service with the Commission. APS will file quarterly transaction summary reports of all short-term transactions under this Tariff stating separately the prices for generation, transmission, and ancillary services.

5.1.2 For long-term transactions (longer than one year), the separate prices for generation, transmission and ancillary services will be included as part of the Service Agreement to be filed with the Commission within 30 days of commencement of service.

5.2 APS may refuse, at its sole discretion, to enter into a Service Agreement or Transaction under this Tariff. APS is under no obligation to execute a Service Agreement to provide service hereunder.

5.3 Acceptance of service by the Customer pursuant to a Service Agreement commits the Customer to the provisions of this Tariff and to the terms of the Service Agreement.

6 EXPANSION OF FACILITIES

APS will have no obligation under this Tariff or any Service Agreement executed hereunder to plan its system, to enlarge or modify its facilities or operate its system in such a manner in order to provide or maintain energy and/or capacity sold hereunder.

7 REASSIGNMENT OF TRANSMISSION RIGHTS

APS may reassign transmission capacity, transmission rights, and associated ancillary services that it has reserved for its own use at a price not to exceed the highest of: (1) the original transmission rate paid by APS; (2) the applicable transmission provider's maximum stated firm transmission rate on file at the time of the transmission reassignment; or (3) APS' own opportunity costs, capped at the applicable transmission providers' cost of expansion at the time of the sale to the eligible customer. APS will not recover opportunity costs in connection with reassignment without making a separate filing under Section 205. Except for the price, the terms and conditions under which the reassignment is made shall be under the terms and conditions governing the original grant by the transmission provider. Transmission and associated ancillary services may only be reassigned to a customer eligible to take service under the transmission provider's open access transmission tariff or other transmission rate schedules. APS will report the name of the assignee in its quarterly reports.

8 **REVISIONS TO TARIFF**

APS may file revisions to this Tariff with the Commission. Nothing contained in this Tariff shall be construed as effecting or limiting in any way the right of APS to unilaterally file with the Commission for a change in any aspect of this Tariff under Section 205 or 206 of the Federal Power Act pursuant to the Commission's Rules and Regulations promulgated thereunder.

9 **EFFECTIVE DATE**

This Tariff shall be effective on the date established by the Commission.

Customer shall incur no obligation by requesting that services be made available.

IN WITNESS WHEREOF, Company and Customer have caused this Service Agreement to be executed by their respective authorized officials as of the date ~~[firs]~~ **first** above written.

ARIZONA PUBLIC SERVICE COMPANY

By: _____

Title: _____

Date: _____

_____
(Customer)

By: _____

Title: _____

Date: _____

---------- COMPARISON OF HEADERS ----------

-HEADER 1-

Arizona Public Service Company Page 5

FERC Electric Tariff, Original Volume No. 4

Market Rate Tariff No. 1

General Terms & Conditions

A

-HEADER 2-

~~[Arizona Public Service Company Page 7~~

~~FERC Electric Tariff, Original Volume No. 4~~

~~Market Rate Tariff No. 1~~

Accepted by FERC _____, 2000

~~[ARIZONA PUBLIC SERVICE COMPANY]~~ **Arizona Public Service Company**

STATEMENT OF POLICY AND CODE OF CONDUCT WITH RESPECT TO THE RELATIONSHIP BETWEEN ARIZONA PUBLIC SERVICE COMPANY AND ~~[APS ENERGY SERVICES COMPANY, INC.]~~ IT'S MARKETING AFFILIATES

The following Code of Conduct will govern ~~[the relationship between (1)]~~ Arizona Public Service ~~[Company ("APS") and (2)]~~ **Company's ("APS") relationship with** APS Energy Services Company, Inc. ("APSES") ~~[or]~~**, Pinnacle West Capital Corporation ("PWCC"), and** any other marketing affiliates that may be authorized by the Federal Energy Regulatory Commission to engage in sales for resale of energy and capacity at market-based rates ~~[(together with APSES,]~~(the "Marketing Affiliates").

Marketing of Power

1. To the maximum extent practical, the employees of the Marketing Affiliates will operate separately from the employees of APS.

2~~[. All market information shared by APS with the Marketing Affiliates will be disclosed simultaneously to the public. This includes all market information, including but not limited to, any communication concerning power or transmission business, present or future, positive or negative, concrete or potential. Shared employees in a support role are not bound by this provision, but they may not serve as an improper conduit of information to non-support personnel.~~

~~3]~~. Sales of any non-power goods or services by APS, including sales made through affiliated EWGs or QFs, to the Marketing Affiliates will be at the higher of cost or market price.

~~[4]~~ **3.** Sales of any non-power goods or services by the Marketing Affiliates to APS will not be at a price above market.

Brokering of Power

1. To the extent APS brokers power sales for the Marketing Affiliates, APS will offer its own power first.

2. APS will charge its Marketing Affiliates the higher of APS' cost for brokering services or the market rate for such services. APS will post the actual brokering charges imposed.

~~[3. APS agrees to simultaneously make public any information shared with the Marketing Affiliates during brokering.]~~

Exhibit C

APS Energy Services Company, Inc.

Conformed Market-Based Rate Tariff,

Conformed Code of Conduct,

Red-Lined Market-Based Rate Tariff

and

Red-Lined Code of Conduct

Exhibit C

APS Energy Services Company, Inc.

Conformed Market-Based Rate Tariff,

Conformed Code of Conduct,

Red-Lined Market-Based Rate Tariff

and

Red-Lined Code of Conduct

APS Energy Services Company, Inc.

MARKET-BASED RATE TARIFF

1. Availability: APS Energy Services Company, Inc. ("APSES") makes electric capacity or energy available for sale for resale under this Rate Schedule to any purchaser.

2. Applicability: This schedule is applicable to all sales of electric capacity or energy by APSES not otherwise subject to a particular rate schedule of APSES.

   This schedule is also available for purchases by the California Independent System Operator Corporation and its suppliers and market participants of Replacement Reserve Service and the following ancillary services as defined by the Commission: Regulation and Frequency Response Service, Energy Imbalance Service, Operating Reserve - Spinning Reserve Service, and Operating Reserve – Supplemental Reserve Service.

   This schedule also is applicable to the reassignment of transmission capacity, transmission rights and associated ancillary services, that APSES has acquired for its own use on the transmission systems of transmission providers.

3. Rates: All sales of electric capacity or energy shall be made at rates established by agreement between the purchaser and APSES.

4. Other Terms and Conditions:

   All other terms and conditions shall be established by agreement between the purchaser and APSES.

5. Effective Date:

   This Rate Schedule shall be effective on the date established by FERC.

6. Reassignment of Transmission Rights:

APSES may reassign transmission capacity, transmission rights, and associated ancillary services that it has reserved for its own use at a price not to exceed the highest of: (1) the original transmission rate paid by APSES; (2) the applicable transmission provider's maximum stated firm transmission rate on file at the time of the transmission reassignment; or (3) APSES's own opportunity costs, capped at the applicable transmission provider's cost of expansion at the time of the sale to the eligible customer. APSES will not recover opportunity costs in connection with reassignment without making a separate filing under Section 205. Except for the price, the terms and conditions under which the reassignment is made shall be under the terms and conditions governing the original grant by the transmission provider. Transmission and associated ancillary services may only be reassigned to a customer eligible to take service under the transmission provider's open access transmission tariff or other transmission rate schedules. APSES will report the name of the assignee in its quarterly reports.

APS Energy Services Company, Inc.

MARKET-BASED RATE TARIFF

SERVICE AGREEMENT

This Service Agreement, dated as of _____, is entered into by and between APS Energy Services Company, Inc. ("APSES") and _____ ("Customer"), pursuant to APSES's Market-Based Rate Tariff, FERC Electric Tariff No. 1 ("Tariff").

Each transaction hereunder will be carried out under terms and conditions as agreed upon by APSES and the Customer in accordance with the terms and conditions of the Tariff.

IN WITNESS WHEREOF, APSES and Customer have caused this Service Agreement to be executed by their respective authorized officials as of the date first above written.

Customer	**APS Energy Services Company, Inc.**
_____	
Customer	
_____	_____
Signature of Representative Date	Signature of Representative Date
_____	_____
Name of Representative	Name of Representative
_____	_____
Title of Representative	Title of Representative

APS Energy Services Company, Inc.

STATEMENT OF POLICY AND CODE OF CONDUCT WITH RESPECT TO THE RELATIONSHIP BETWEEN APS ENERGY SERVICES COMPANY, INC. AND ARIZONA PUBLIC SERVICE COMPANY

The following Code of Conduct will govern the relationship between APS Energy Services Company, Inc. ("APSES") and any other marketing affiliates that may be authorized by the Federal Energy Regulatory Commission to engage in sales for resale of energy and capacity at market-based rates (the "Marketing Affiliates"), and Arizona Public Service Company ("APS").

Marketing of Power

1. To the maximum extent practical, the employees of the Marketing Affiliates will operate separately from the employees of APS.

2. Sales of any non-power goods or services by APS, including sales made through affiliated EWGs or QFs, to the Marketing Affiliates will be at the higher of cost or market price.

3. Sales of any non-power goods or services by the Marketing Affiliates to APS will not be at a price above market.

Brokering of Power

To the extent Marketing Affiliates seek to broker power for APS:

4. Marketing Affiliates will offer APS's power first.

5. The arrangement between Marketing Affiliates and APS is non-exclusive.

6. Marketing Affiliates will not accept any fees in conjunction with any brokering services they perform for APS.

APS Energy Services Company, Inc.

MARKET-BASED RATE TARIFF

1. Availability: APS Energy Services Company, Inc. ("APSES") makes electric capacity or energy available for sale for resale under this Rate Schedule to any purchaser.

2. Applicability: This schedule is applicable to all sales of electric capacity or energy by APSES not otherwise subject to a particular rate schedule of APSES~~[, but shall not apply to the sales of electric capacity or energy to, or the purchase of electric capacity or energy from Arizona Public Service Company ("APS")]~~.

   This schedule is also available for purchases by the California Independent System Operator Corporation and its suppliers and market participants of Replacement Reserve Service and the following ancillary services as defined by the Commission: Regulation and Frequency Response Service, Energy Imbalance Service, Operating Reserve - Spinning Reserve Service, and Operating Reserve – Supplemental Reserve Service.

   This schedule also is applicable to the reassignment of transmission capacity, transmission rights and associated ancillary services, that APSES has acquired for its own use on the transmission systems of transmission providers.

3. Rates: All sales of electric capacity or energy shall be made at rates established by agreement between the purchaser and APSES.

4. Other Terms and Conditions:

   All other terms and conditions shall be established by agreement between the purchaser and APSES.

~~[APSES will not sell electric capacity or energy to, or purchase electric capacity or energy from APS, absent a separate filing with FERC pursuant to Section 205 of the Federal Power Act.]~~

5. Effective Date:

   This Rate Schedule shall be effective on the date established by FERC.

6. Reassignment of Transmission Rights:

APSES may reassign transmission capacity, transmission rights, and associated ancillary services that it has reserved for its own use at a price not to exceed the highest of: (1) the original transmission rate paid by APSES; (2) the applicable transmission provider's maximum stated firm transmission rate on file at the time of the transmission reassignment; or (3) APSES's own opportunity costs, capped at the applicable transmission provider's cost of expansion at the time of the sale to the eligible customer. APSES will not recover opportunity costs in connection with reassignment without making a separate filing under Section 205. Except for the price, the terms and conditions under which the reassignment is made shall be under the terms and conditions governing the original grant by the transmission provider. Transmission and associated ancillary services may only be reassigned to a customer eligible to take service under the transmission provider's open access transmission tariff or other transmission rate schedules. APSES will report the name of the assignee in its quarterly reports.

APS Energy Services Company, Inc.

MARKET-BASED RATE TARIFF

SERVICE AGREEMENT

This Service Agreement, dated as of

[_____] _____, is entered into by and between APS Energy Services Company, Inc. ("APSES") and

[_____] _____

("Customer"), pursuant to APSES's Market-Based Rate Tariff, FERC Electric Tariff No. 1 **("Tariff")**.

Each transaction hereunder will be carried out under terms and conditions as agreed upon by APSES and the Customer in accordance with the terms and conditions of the ~~[Rate Schedule]~~ **Tariff**.

IN WITNESS WHEREOF, APSES and Customer have caused this Service Agreement to be executed by their respective authorized officials as of the date first above written.

Customer	**APS Energy Services Company, Inc.**
_____	
Customer	
_____	
_____	[_____]
Signature of Representative Date	Signature of Representative Date
_____	
_____	[_____]
Name of Representative	Name of Representative
_____	_____

APS ~~[ENERGY SERVICES COMPANY, INC]~~ Energy Services Company, Inc.

STATEMENT OF POLICY AND CODE OF CONDUCT WITH RESPECT TO THE RELATIONSHIP BETWEEN APS ENERGY SERVICES COMPANY, INC. AND ARIZONA PUBLIC SERVICE COMPANY

The following Code of Conduct will govern the relationship between ~~[(1)]~~ APS Energy Services Company, Inc. ("APSES") and any other ~~[marketer]~~ **marketing** affiliates that may be authorized by the Federal Energy Regulatory Commission to engage in sales for resale of energy and capacity at market-based rates ~~[(together with APSES,]~~(the "Marketing Affiliates"), and ~~[(2)]~~ Arizona Public Service Company ("APS").

Marketing of Power

1. To the maximum extent practical, the employees of the Marketing Affiliates will operate separately from the employees of APS.

2~~[. All market information shared by APS with the Marketing Affiliates will be disclosed simultaneously to the public. This includes all market information, including but not limited to, any communication concerning power or transmission business, present or future, positive or negative, concrete or potential. Shared employees in a support role are not bound by this provision, but they may not serve as an improper conduit of information to non-support personnel.~~

~~3]~~. Sales of any non-power goods or services by APS, including sales made through affiliated EWGs or QFs, to the Marketing Affiliates will be at the higher of cost or market price.

~~[4]~~ **3.** Sales of any non-power goods or services by the Marketing Affiliates to APS will not be at a price above market.

Brokering of Power

To the extent Marketing Affiliates seek to broker power for APS:

4. Marketing Affiliates will offer APS's power first.

5. The arrangement between Marketing Affiliates and APS is non-exclusive.

6. Marketing Affiliates will not accept any fees in conjunction with any brokering services they perform for APS.

Exhibit D

Revision to APS' Wholesale Contracts

Containing System Incremental Cost Pricing Provisions

Arizona Public Service Company

FERC Electric Coordination Tariff No. 1, Revision No. 4

Conformed & Red-Lined Copy

Appendix A-1

ARIZONA PUBLIC SERVICE COMPANY

Units Most Likely To Participate Methodology

Determination of Ceiling Rates Applicable to Sales of Coordination Power and Energy Under Service Schedule A.

A. Generation Related Rate Component:

I. For sales of Coordination Power and Energy made by APS from certain APS resources, Purchaser shall pay a charge for unbundled generation related service not to exceed the following amounts to APS for Power and Energy supplied under Service Schedule A:

Maximum Demand Charge:[1]

Annual	$	60.93/kW
Monthly	$	5.08/kW
Weekly	$	1.17/kW
Daily	$	0.23/kW[2]
Hourly	$	0.0144/kW[3]

plus

Energy Charge:

a) no less than 100% of APS' System Incremental Costs (SIC); plus
b) up to 10% of SIC

Provided, however, the monthly ceiling rate as defined above shall be the lesser of this rate: (i) developed utilizing the aggregate of APS' actual hourly SIC values during the month, or (ii) the rate as developed utilizing an aggregate of an hourly cents/kWh index in lieu of SIC. The hourly cents/kWh index shall be based on a Palo Verde Shaped Index[4].

---

[1] The Maximum Demand Charge for weekly, daily and hourly periods were computed utilizing the "AEP" methodology.

[2] The Daily rate of $0.23/kW shall not exceed the product of the number of kilowatts sold for a week multiplied by the maximum weekly demand charge of $1.17/kW.

[3] The hourly rate of $0.0144/kW shall not exceed the product of the number of kilowatts sold for a day multiplied by the maximum daily demand charge of $0.23/kW, and also not exceed the product of the number of kilowatts sold for a week multiplied by the maximum weekly demand charge of $1.17/kW.

[4] The Hourly Palo Verde Shaped Index shall be determined as shown on Table A.

II. When a sale of Coordination Power and Energy made by APS is conditioned upon APS acquiring Purchased Power, Purchaser shall pay the following amounts to APS for Power and Energy supplied under this Service Schedule A:

a) APS' actual Purchased Power costs

III. Purchaser shall also be responsible for any taxes, purchased power costs, and for any other costs incurred by APS in fulfilling its obligations for Coordination Power under this Service Schedule A which otherwise would not have been incurred.

B. <u>Transmission and Ancillary Service Rate Components:</u>

I. Purchaser shall be required to secure transmission and ancillary services from APS' Transmission Group on its own behalf. If Purchaser obtains the required transmission and ancillary services, APS shall file a service agreement with the FERC placing the Purchaser under APS' Open Access Transmission Tariff. All pertinent arrangements for such services can be made directly with APS' Transmission Group personnel at:

Arizona Public Service Company
P.O. Box 53999; Station 2260
Phoenix, Arizona 85072-3999
Facsimile No. (602) 250-1127

II. In the alternative, Purchaser may request that APS' Merchant Group secure all transmission and ancillary services under APS' Open Access Transmission Tariff required to effect service to Purchaser. APS' Merchant Group shall have the option to decline such requests.

Should the APS Merchant Group secure all transmission and related services, an appropriate Open Access Transmission Tariff Service Agreement shall be filed with the Federal Energy Regulatory Commission.

The unbundled rate components for each transmission and ancillary service assessed to the Purchaser for Power and/or Energy under this Electric Coordination Tariff No. 1 are listed on Attachment A.

Appendix A-2

ARIZONA PUBLIC SERVICE COMPANY

Unit Revenue Constraint Methodology

Determination of Ceiling Rates Applicable to Sales of Coordination Power and Energy Under Service Schedule A

A. Generation Related Rate Component:

I. For sales of Coordination Power and Energy made by APS based on the costs of Palo Verde Unit No. 3, Purchaser shall pay a charge for unbundled generation related service not to exceed the following amounts to APS for Power and Energy supplied under Service Schedule A:

Maximum Demand Charge:[5]

Annual	$ 438.80/kW
Monthly	$ 36.57/kW
Weekly	$ 8.44/kW
Daily	$ 1.69/kW[6]
Hourly	$ 0.1056/kW[7]

plus

Energy Charge:

a) no less than 100% of APS' System Incremental Costs (SIC), plus
b) up to 10% of SIC

Note A: The total charges for Power and Energy shall not exceed the product of the requested demand (kW) multiplied by the applicable Maximum Demand Charge in Section I above, plus the variable costs of Palo Verde Unit No. 3 (based on the second previous month's cost data), and not withstanding the foregoing, a floor equal to 100% of APS' System Incremental Cost.

Note B: The total amount of Power available for sales by APS under this Service Schedule and under other APS tariffs and agreements, for which the agreed upon demand

---

[5] The Maximum Demand Charge for weekly, daily and hourly periods were computed utilizing the "AEP" methodology.

[6] The Daily rate of $1.69/kW shall not exceed the product of the number of kilowatts sold for a week multiplied by the maximum weekly demand charge of $8.44/kW.

[7] The hourly rate of $0.1056/kW shall not exceed the product of the number of kilowatts sold for a day multiplied by the maximum daily demand charge of $1.69/kW, and also not exceed the product of the number of kilowatts sold for a week multiplied by the maximum weekly demand charge of $8.44/kW.

charge is determined based on Palo Verde Unit No. 3, is limited to 370 MWs (APS' share of Palo Verde No. 3) on an hourly basis.

Provided, however, the monthly ceiling rate and the monthly floor rate as defined above shall be the lesser of these rates: (i) developed utilizing the aggregate of APS' actual hourly SIC values during the month, or (ii) the rates as developed utilizing an aggregate of an hourly cents/kWh index in lieu of SIC. The hourly cents/kWh index shall be based on a Palo Verde Shaped Index[8].

II. When a sale of Coordination Power and Energy made by APS is conditioned upon APS acquiring Purchased Power, Purchaser shall pay the following amounts to APS for Power and Energy supplied under this Service Schedule A:

a) APS' actual Purchased Power costs

III. Purchaser shall also be responsible for any taxes, purchased power costs, and for any other costs incurred by APS in fulfilling its obligations for Coordination Power under this Service Schedule A which otherwise would not have been incurred.

B. <u>Transmission and Ancillary Service Rate Components:</u>

I. Purchaser shall be required to secure transmission and ancillary services from APS' Transmission Group on its own behalf. If Purchaser obtains the required transmission and ancillary services, APS shall file a service agreement with the FERC placing the Purchaser under APS' Open Access Transmission Tariff. All pertinent arrangements for such services can be made directly with APS' Transmission Group personnel at:

Arizona Public Service Company
P.O. Box 53999; Station 2260
Phoenix, Arizona 85072-3999
Facsimile No. (602) 250-1127

II. In the alternative, Purchaser may request that APS' Merchant Group secure all transmission and ancillary services under APS' Open Access Transmission Tariff required to effect service to Purchaser. APS' Merchant Group shall have the option to decline such requests.

Should the APS Merchant Group secure all transmission and related services, an appropriate Open Access Transmission Tariff Service Agreement shall be filed with the Federal Energy Regulatory Commission.

The unbundled rate components for each transmission and ancillary service assessed to the Purchaser for Power and/or Energy under this Electric Coordination Tariff No. 1 are listed on Attachment A.

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[8] The Hourly Palo Verde Shaped Index shall be determined as shown on Table A.

Appendix B-1

ARIZONA PUBLIC SERVICE COMPANY

Units Most Likely to Participate Methodology

Determination of Ceiling Rates Applicable to Non-Returned Power and Energy Under Service Schedule B

A. Generation Related Rate Component:

I. For sales of non–returned Power and Energy exchange deliveries made by APS from certain APS resources, Purchaser shall pay a charge for unbundled generation related service not to exceed the following amounts to APS for Power and Energy supplied under this Service Schedule B:

Maximum Demand Charge:[1]

Annual	$	60.93/kW
Monthly	$	5.08/kW
Weekly	$	1.17/kW
Daily	$	0.23/kW[2]
Hourly	$	0.0144/kW[3]

plus

Energy Charge:

a) no less than 100% of APS' System Incremental Costs (SIC), plus
b) up to 10% of SIC

Provided, however, the monthly ceiling rate as defined above shall be the lesser of this rate: (i) developed utilizing the aggregate of APS' actual hourly SIC values during the month, or (ii) the rate as developed utilizing an aggregate of an hourly cents/kWh index in lieu of SIC. The hourly cents/kWh index shall be based on a Palo Verde Shaped Index[4].

---

[1] The Maximum Demand Charge for weekly, daily and hourly periods were computed utilizing the "AEP" methodology.

[2] The Daily rate of $0.23/kW shall not exceed the product of the number of kilowatts sold for a week multiplied by the maximum weekly demand charge of $1.17/kW.

[3] The hourly rate of $0.0144/kW shall not exceed the product of the number of kilowatts sold for a day multiplied by the maximum daily demand charge of $0.23/kW, and also not exceed the product of the number of kilowatts sold for a week multiplied by the maximum weekly demand charge of $1.17/kW.

[4] The Hourly Palo Verde Shaped Index shall be determined as shown on Table A.

II. When a sale of Coordination Power and Energy made by APS is conditioned upon APS acquiring Purchased Power, Purchaser shall pay the following amounts to APS for Power and Energy supplied under this Service Schedule B:

a) APS' actual Purchased Power costs

III. Purchaser shall also be responsible for any taxes, purchased power costs, and for any other costs incurred by APS in fulfilling its obligations for Coordination Power under this Service Schedule B which otherwise would not have been incurred.

B. Transmission and Ancillary Service Rate Components:

I. The Parties recognize that separate arrangements must be made for all required transmission and ancillary services associated with Power and Energy Exchange transactions. The Parties may negotiate the responsibility for costs related to all required transmission and ancillary services. If Purchaser obtains the required transmission and ancillary services, APS shall file a service agreement with the FERC placing the Purchaser under APS' Open Access Transmission Tariff. All pertinent arrangements for such services can be made directly with APS' Transmission Group personnel at:

Arizona Public Service Company
P.O. Box 53999; Station 2260
Phoenix, Arizona 85072-3999
Facsimile No. (602) 250-1127

II. In the alternative, Purchaser may request that APS' Merchant Group secure all transmission and ancillary services under APS' Open Access Transmission Tariff required to effect service to Purchaser. APS' Merchant Group shall have the option to decline such requests.

Should the APS Merchant Group secure all transmission and related services, an appropriate Open Access Transmission Tariff Service Agreement shall be filed with the Federal Energy Regulatory Commission.

The unbundled rate components for each transmission and ancillary service assessed to the Purchaser for Power and/or Energy under this Electric Coordination Tariff No. 1 are listed on Attachment A.

Appendix B-2

ARIZONA PUBLIC SERVICE COMPANY

Unit Revenue Constraint Methodology

Determination of Ceiling Rates Applicable to Non-Returned Power and Energy Under Service Schedule B

A. Generation Related Rate Component:

I. For sales of non–returned Power and Energy exchange deliveries made by APS based on the costs of Palo Verde Unit No. 3, Purchaser shall pay a charge for unbundled generation related service not to exceed the following amounts to APS for Power and Energy supplied under this Service Schedule B:

Maximum Demand Charge:[5]

Annual	$ 438.80/kW
Monthly	$ 36.57/kW
Weekly	$ 8.44/kW
Daily	$ 1.69/kW[6]
Hourly	$ 0.1056/kW[7]

plus

Energy Charge:

a) no less than 100% of APS' System Incremental Costs (SIC), plus
b) up to 10% of SIC

Note A: The total charges for Power and Energy shall not exceed the product of the requested demand (kW) multiplied by the applicable Maximum Demand Charge in Section I above, plus the variable costs of Palo Verde Unit No. 3 (based on the second previous month's cost data), and not withstanding the foregoing, a floor equal to 100% of APS' System Incremental Cost.

Note B: The total amount of Power available for sales by APS under this Service Schedule and under other APS tariffs and agreements, for which the agreed upon demand

[5] The Maximum Demand Charge for weekly, daily and hourly periods were computed utilizing the "AEP" methodology.

[6] The Daily rate of $1.69/kW shall not exceed the product of the number of kilowatts sold for a week multiplied by the maximum weekly demand charge of $8.44/kW.

[7] The hourly rate of $0.1056/kW shall not exceed the product of the number of kilowatts sold for a day multiplied by the maximum daily demand charge of $1.69/kW, and also not exceed the product of the number of kilowatts sold for a week multiplied by the maximum weekly demand charge of $8.44/kW.

charge is determined based on Palo Verde Unit No. 3, is limited to 370 MWs (APS' share of Palo Verde No. 3) on an hourly basis.

Provided, however, the monthly ceiling rate and the monthly floor rate as defined above shall be the lesser of these rates: (i) developed utilizing the aggregate of APS' actual hourly SIC values during the month, or (ii) the rates as developed utilizing an aggregate of an hourly cents/kWh index in lieu of SIC. The hourly cents/kWh index shall be based on a Palo Verde Shaped Index[8].

II. When a sale of Coordination Power and Energy made by APS is conditioned upon APS acquiring Purchased Power, Purchaser shall pay the following amounts to APS for Power and Energy supplied under this Service Schedule B:

a) APS' actual Purchased Power costs

III. Purchaser shall also be responsible for any taxes, purchased power costs, and for any other costs incurred by APS in fulfilling its obligations for Coordination Power under this Service Schedule B which otherwise would not have been incurred.

B. <u>Transmission and Ancillary Service Rate Components:</u>

I. The Parties recognize that separate arrangements must be made for all required transmission and ancillary services associated with Power and Energy Exchange transactions. The Parties may negotiate the responsibility for costs related to all required transmission and ancillary services. If Purchaser obtains the required transmission and ancillary services, APS shall file a service agreement with the FERC placing the Purchaser under APS' Open Access Transmission Tariff. All pertinent arrangements for such services can be made directly with APS' Transmission Group personnel at:

Arizona Public Service Company
P.O. Box 53999; Station 2260
Phoenix, Arizona 85072-3999
Facsimile No. (602) 250-1127

II. In the alternative, Purchaser may request that APS' Merchant Group secure all transmission and ancillary services under APS' Open Access Transmission Tariff required to effect service to Purchaser. APS' Merchant Group shall have the option to decline such requests.

Should the APS Merchant Group secure all transmission and related services, an appropriate Open Access Transmission Tariff Service Agreement shall be filed with the Federal Energy Regulatory Commission.

The unbundled rate components for each transmission and ancillary service assessed to the Purchaser for Power and/or Energy under this Electric Coordination Tariff No. 1 are listed on Attachment A.

[8] The Hourly Palo Verde Shaped Index shall be determined as shown on Table A.

EXAMPLE OF DETERMINATION OF THE PALO VERDE SHAPED INDEX

TABLE A

Date	ou	SP-15 (1) Index $/MWh	PV Index (2) Firm Price On Peak $/MWh	PV Index (2) Firm Price Off Peak $/MWh	PV Shaped Index (3) ($/MWh)
9/1/1998	1	28.52		32.50	34.13
9/1/1998	2	27.48		32.50	32.88
9/1/1998	3	26.18		32.50	31.33
9/1/1998	4	25.48		32.50	30.49
9/1/1998	5	25.60		32.50	30.63
9/1/1998	6	27.55		32.50	32.97
9/1/1998	7	28.16	91.89		25.93
9/1/1998	8	29.37	91.89		27.04
9/1/1998	9	37.49	91.89		34.52
9/1/1998	10	49.00	91.89		45.12
9/1/1998	11	88.36	91.89		81.36
9/1/1998	12	102.84	91.89		94.70
9/1/1998	13	122.68	91.89		112.97
9/1/1998	14	136.86	91.89		126.03
9/1/1998	15	155.10	91.89		142.82
9/1/1998	16	167.06	91.89		153.83
9/1/1998	17	165.19	91.89		152.11
9/1/1998	18	141.53	91.89		130.33
9/1/1998	19	118.06	91.89		108.71
9/1/1998	20	104.99	91.89		96.68
9/1/1998	21	99.90	91.89		91.99
9/1/1998	22	50.00	91.89		46.04
9/1/1998	23	28.17		32.50	33.71
9/1/1998	24	28.29		32.50	33.85
Average for Day SP-15 on-peak			99.79	Avg PV Indx shaped onpk	91.89
Average for Day SP-15 off-peak			27.16	Avg PV Indx shaped offpk	32.50

Date	Hou	SP-15 (1) Index $/MWh	PV Index (2) Firm Price On Peak $/MWh	PV Index (2) Firm Price Off Peak $/MWh	PV Shaped Index (3) ($/MWh)
4/28/1999	1	14.50		14.88	14.43
4/28/1999	2	13.50		14.88	13.44
4/28/1999	3	11.52		14.88	11.47
4/28/1999	4	11.65		14.88	11.60
4/28/1999	5	12.00		14.88	11.94
4/28/1999	6	15.49		14.88	15.42
4/28/1999	7	24.32	26.85		22.67
4/28/1999	8	31.50	26.85		29.37
4/28/1999	9	30.59	26.85		28.52
4/28/1999	10	30.99	26.85		28.89
4/28/1999	11	29.71	26.85		27.70
4/28/1999	12	28.99	26.85		27.03
4/28/1999	13	28.49	26.85		26.56
4/28/1999	14	28.00	26.85		26.10
4/28/1999	15	27.49	26.85		25.63
4/28/1999	16	26.89	26.85		25.07
4/28/1999	17	26.84	26.85		25.02
4/28/1999	18	26.75	26.85		24.94
4/28/1999	19	26.28	26.85		24.50
4/28/1999	20	29.50	26.85		27.50
4/28/1999	21	35.00	26.85		32.63
4/28/1999	22	29.50	26.85		27.50
4/28/1999	23	23.64		14.88	23.53
4/28/1999	24	17.32		14.88	17.24
Average for Day SP-15 on-peak			28.80	Avg PV Indx shaped onpk	26.85
Average for Day SP-15 off-peak			14.95	Avg PV Indx shaped offpk	14.88

NOTES: (1) California Power Exchange (CalPX) Day Ahead Hourly SP-15 Post Congestion Index ("SP-15"). Found on Website: www. CALPX.com. For specific instructions: Get on website:http://www.calpx.com/prices/index_prices_dayahead_trading.html Then select the "Hourly Zonal Prices Constrained Report" and the dates you want. (For this example select 9/1/98) Hit the "view" key. Scroll over to SP-15 (right side) and look at the price. It should be $28.52 for hour 1.

(2) Dow Jones Palo Verde Daily On and Off-Peak Index. This index can be found for three current months on website http://www.energyonline.com/Restructuring/energydb/estathme.html.

(3) The on-peak value of the Palo Verde Shaped Index is calculated by taking the ratio of the SP-15 Index hourly value on-peak divide it by the SP-15 average daily on-peak values, times the Palo Verde On-Peak value for the day. The off-peak value for PV Shaped Index is calculted using SP-15 off-peak values in the ratio times the PV off-peak value for the day.

PV Index Shaped = SP-15 hourly value/SP15 Average of Daily Values X PV Index for same hour.

Appendix A-1

ARIZONA PUBLIC SERVICE COMPANY

Units Most Likely To Participate Methodology

Determination of Ceiling Rates Applicable to Sales of Coordination Power and Energy Under Service Schedule A.

A. **Generation Related Rate Component:**

I. For sales of Coordination Power and Energy made by APS from certain APS resources, Purchaser shall pay a charge for unbundled generation related service not to exceed the following amounts to APS for Power and Energy supplied under Service Schedule A:

Maximum Demand Charge:[1]

Annual	$	60.93/kW
Monthly	$	5.08/kW
Weekly	$	1.17/kW
Daily	$	0.23/kW[2]
Hourly	$	0.0144/kW[3]

plus

Energy Charge:

a) no less than 100% of APS' System Incremental Costs (SIC); plus
b) up to 10% of SIC

Provided, however, the monthly ceiling rate as defined above shall be the lesser of this rate: (i) developed utilizing the aggregate of APS' actual hourly SIC values during the month, or (ii) the rate as developed utilizing an aggregate of an hourly cents/kWh index in lieu of SIC. The hourly cents/kWh index shall be based on a Palo Verde Shaped Index[4].

II. When a sale of Coordination Power and Energy made by APS is conditioned upon APS acquiring Purchased Power, Purchaser shall pay the following amounts to APS for Power and Energy supplied under this Service Schedule A:

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[1] The Maximum Demand Charge for weekly, daily and hourly periods were computed utilizing the "AEP" methodology.

[2] The Daily rate of $0.23/kW shall not exceed the product of the number of kilowatts sold for a week multiplied by the maximum weekly demand charge of $1.17/kW.

[3] The hourly rate of $0.0144/kW shall not exceed the product of the number of kilowatts sold for a day multiplied by the maximum daily demand charge of $0.23/kW, and also not exceed the product of the number of kilowatts sold for a week multiplied by the maximum weekly demand charge of $1.17/kW.

[4] The Hourly Palo Verde Shaped Index shall be determined as shown on Table A.

a) APS' actual Purchased Power costs

III. Purchaser shall also be responsible for any taxes, purchased power costs, and for any other costs incurred by APS in fulfilling its obligations for Coordination Power under this Service Schedule A which otherwise would not have been incurred.

B. Transmission and Ancillary Service Rate Components:

I. Purchaser shall be required to secure transmission and ancillary services from APS' Transmission Group on its own behalf. If Purchaser obtains the required transmission and ancillary services, APS shall file a service agreement with the FERC placing the Purchaser under APS' Open Access Transmission Tariff. All pertinent arrangements for such services can be made directly with APS' Transmission Group personnel at:

Arizona Public Service Company
P.O. Box 53999; Station 2260
Phoenix, Arizona 85072-3999
Facsimile No. (602) 250-1127

II. In the alternative, Purchaser may request that APS' Merchant Group secure all transmission and ancillary services under APS' Open Access Transmission Tariff required to effect service to Purchaser. APS' Merchant Group shall have the option to decline such requests.

Should the APS Merchant Group secure all transmission and related services, an appropriate Open Access Transmission Tariff Service Agreement shall be filed with the Federal Energy Regulatory Commission.

The unbundled rate components for each transmission and ancillary service assessed to the Purchaser for Power and/or Energy under this Electric Coordination Tariff No. 1 are listed on Attachment A.

Appendix A-2

ARIZONA PUBLIC SERVICE COMPANY

Unit Revenue Constraint Methodology

Determination of Ceiling Rates Applicable to Sales of Coordination Power and Energy Under Service Schedule A

A. Generation Related Rate Component:

I. For sales of Coordination Power and Energy made by APS based on the costs of Palo Verde Unit No. 3, Purchaser shall pay a charge for unbundled generation related service not to exceed the following amounts to APS for Power and Energy supplied under Service Schedule A:

Maximum Demand Charge:[5]

Annual	$ 438.80/kW
Monthly	$ 36.57/kW
Weekly	$ 8.44/kW
Daily	$ 1.69/kW[6]
Hourly	$ 0.1056/kW[7]

plus

Energy Charge:

a) no less than 100% of APS' System Incremental Costs (SIC), plus
b) up to 10% of SIC

Note A: The total charges for Power and Energy shall not exceed the product of the requested demand (kW) multiplied by the applicable Maximum Demand Charge in Section I above, plus the variable costs of Palo Verde Unit No. 3 (based on the second previous month's cost data), and not withstanding the foregoing, a floor equal to 100% of APS' System Incremental Cost.

Note B: The total amount of Power available for sales by APS under this Service Schedule and under other APS tariffs and agreements, for which the agreed upon demand

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[5] The Maximum Demand Charge for weekly, daily and hourly periods were computed utilizing the "AEP" methodology.

[6] The Daily rate of $1.69/kW shall not exceed the product of the number of kilowatts sold for a week multiplied by the maximum weekly demand charge of $8.44/kW.

[7] The hourly rate of $0.1056/kW shall not exceed the product of the number of kilowatts sold for a day multiplied by the maximum daily demand charge of $1.69/kW, and also not exceed the product of the number of kilowatts sold for a week multiplied by the maximum weekly demand charge of $8.44/kW.

charge is determined based on Palo Verde Unit No. 3, is limited to 370 MWs (APS' share of Palo Verde No. 3) on an hourly basis.

Provided, however, the monthly ceiling rate and the monthly floor rate as defined above shall be the lesser of these rates: (i) developed utilizing the aggregate of APS' actual hourly SIC values during the month, or (ii) the rates as developed utilizing an aggregate of an hourly cents/kWh index in lieu of SIC. The hourly cents/kWh index shall be based on a Palo Verde Shaped Index[8].

II. When a sale of Coordination Power and Energy made by APS is conditioned upon APS acquiring Purchased Power, Purchaser shall pay the following amounts to APS for Power and Energy supplied under this Service Schedule A:

a) APS' actual Purchased Power costs

III. Purchaser shall also be responsible for any taxes, purchased power costs, and for any other costs incurred by APS in fulfilling its obligations for Coordination Power under this Service Schedule A which otherwise would not have been incurred.

B. Transmission and Ancillary Service Rate Components:

I. Purchaser shall be required to secure transmission and ancillary services from APS' Transmission Group on its own behalf. If Purchaser obtains the required transmission and ancillary services, APS shall file a service agreement with the FERC placing the Purchaser under APS' Open Access Transmission Tariff. All pertinent arrangements for such services can be made directly with APS' Transmission Group personnel at:

Arizona Public Service Company
P.O. Box 53999; Station 2260
Phoenix, Arizona 85072-3999
Facsimile No. (602) 250-1127

II. In the alternative, Purchaser may request that APS' Merchant Group secure all transmission and ancillary services under APS' Open Access Transmission Tariff required to effect service to Purchaser. APS' Merchant Group shall have the option to decline such requests.

Should the APS Merchant Group secure all transmission and related services, an appropriate Open Access Transmission Tariff Service Agreement shall be filed with the Federal Energy Regulatory Commission.

The unbundled rate components for each transmission and ancillary service assessed to the Purchaser for Power and/or Energy under this Electric Coordination Tariff No. 1 are listed on Attachment A.

[8] The Hourly Palo Verde Shaped Index shall be determined as shown on Table A.

Appendix B-1

ARIZONA PUBLIC SERVICE COMPANY

Units Most Likely to Participate Methodology

Determination of Ceiling Rates Applicable to Non-Returned Power and Energy Under Service Schedule B

A. Generation Related Rate Component:

I. For sales of non–returned Power and Energy exchange deliveries made by APS from certain APS resources, Purchaser shall pay a charge for unbundled generation related service not to exceed the following amounts to APS for Power and Energy supplied under this Service Schedule B:

Maximum Demand Charge:[1]

Annual	$	60.93/kW
Monthly	$	5.08/kW
Weekly	$	1.17/kW
Daily	$	0.23/kW[2]
Hourly	$	0.0144/kW[3]

plus

Energy Charge:

a) no less than 100% of APS' System Incremental Costs (SIC), plus
b) up to 10% of SIC

Provided, however, the monthly ceiling rate as defined above shall be the lesser of this rate: (i) developed utilizing the aggregate of APS' actual hourly SIC values during the month, or (ii) the rate as developed utilizing an aggregate of an hourly cents/kWh index in lieu of SIC. The hourly cents/kWh index shall be based on a Palo Verde Shaped Index[4].

[1] The Maximum Demand Charge for weekly, daily and hourly periods were computed utilizing the "AEP" methodology.

[2] The Daily rate of $0.23/kW shall not exceed the product of the number of kilowatts sold for a week multiplied by the maximum weekly demand charge of $1.17/kW.

[3] The hourly rate of $0.0144/kW shall not exceed the product of the number of kilowatts sold for a day multiplied by the maximum daily demand charge of $0.23/kW, and also not exceed the product of the number of kilowatts sold for a week multiplied by the maximum weekly demand charge of $1.17/kW.

[4] The Hourly Palo Verde Shaped Index shall be determined as shown on Table A.

II. When a sale of Coordination Power and Energy made by APS is conditioned upon APS acquiring Purchased Power, Purchaser shall pay the following amounts to APS for Power and Energy supplied under this Service Schedule B:

a) APS' actual Purchased Power costs

III. Purchaser shall also be responsible for any taxes, purchased power costs, and for any other costs incurred by APS in fulfilling its obligations for Coordination Power under this Service Schedule B which otherwise would not have been incurred.

B. Transmission and Ancillary Service Rate Components:

I. The Parties recognize that separate arrangements must be made for all required transmission and ancillary services associated with Power and Energy Exchange transactions. The Parties may negotiate the responsibility for costs related to all required transmission and ancillary services. If Purchaser obtains the required transmission and ancillary services, APS shall file a service agreement with the FERC placing the Purchaser under APS' Open Access Transmission Tariff. All pertinent arrangements for such services can be made directly with APS' Transmission Group personnel at:

Arizona Public Service Company
P.O. Box 53999; Station 2260
Phoenix, Arizona 85072-3999
Facsimile No. (602) 250-1127

II. In the alternative, Purchaser may request that APS' Merchant Group secure all transmission and ancillary services under APS' Open Access Transmission Tariff required to effect service to Purchaser. APS' Merchant Group shall have the option to decline such requests.

Should the APS Merchant Group secure all transmission and related services, an appropriate Open Access Transmission Tariff Service Agreement shall be filed with the Federal Energy Regulatory Commission.

The unbundled rate components for each transmission and ancillary service assessed to the Purchaser for Power and/or Energy under this Electric Coordination Tariff No. 1 are listed on Attachment A.

Appendix B-2

ARIZONA PUBLIC SERVICE COMPANY

Unit Revenue Constraint Methodology

Determination of Ceiling Rates Applicable to Non-Returned Power and Energy Under Service Schedule B

A. Generation Related Rate Component:

1. For sales of non–returned Power and Energy exchange deliveries made by APS based on the costs of Palo Verde Unit No. 3, Purchaser shall pay a charge for unbundled generation related service not to exceed the following amounts to APS for Power and Energy supplied under this Service Schedule B:

Maximum Demand Charge:[5]

Annual	$ 438.80/kW
Monthly	$ 36.57/kW
Weekly	$ 8.44/kW
Daily	$ 1.69/kW[6]
Hourly	$ 0.1056/kW[7]

plus

Energy Charge:

a) no less than 100% of APS' System Incremental Costs (SIC), plus
b) up to 10% of SIC

Note A: The total charges for Power and Energy shall not exceed the product of the requested demand (kW) multiplied by the applicable Maximum Demand Charge in Section I above, plus the variable costs of Palo Verde Unit No. 3 (based on the second previous month's cost data), and not withstanding the foregoing, a floor equal to 100% of APS' System Incremental Cost.

Note B: The total amount of Power available for sales by APS under this Service Schedule and under other APS tariffs and agreements, for which the agreed upon demand

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[5] The Maximum Demand Charge for weekly, daily and hourly periods were computed utilizing the "AEP" methodology.

[6] The Daily rate of $1.69/kW shall not exceed the product of the number of kilowatts sold for a week multiplied by the maximum weekly demand charge of $8.44/kW.

[7] The hourly rate of $0.1056/kW shall not exceed the product of the number of kilowatts sold for a day multiplied by the maximum daily demand charge of $1.69/kW, and also not exceed the product of the number of kilowatts sold for a week multiplied by the maximum weekly demand charge of $8.44/kW.

charge is determined based on Palo Verde Unit No. 3, is limited to 370 MWs (APS' share of Palo Verde No. 3) on an hourly basis.

Provided, however, the monthly ceiling rate and the monthly floor rate as defined above shall be the lesser of these rates: (i) developed utilizing the aggregate of APS' actual hourly SIC values during the month, or (ii) the rates as developed utilizing an aggregate of an hourly cents/kWh index in lieu of SIC. The hourly cents/kWh index shall be based on a Palo Verde Shaped Index[8].

II. When a sale of Coordination Power and Energy made by APS is conditioned upon APS acquiring Purchased Power, Purchaser shall pay the following amounts to APS for Power and Energy supplied under this Service Schedule B:

a) APS' actual Purchased Power costs

III. Purchaser shall also be responsible for any taxes, purchased power costs, and for any other costs incurred by APS in fulfilling its obligations for Coordination Power under this Service Schedule B which otherwise would not have been incurred.

B. Transmission and Ancillary Service Rate Components:

I. The Parties recognize that separate arrangements must be made for all required transmission and ancillary services associated with Power and Energy Exchange transactions. The Parties may negotiate the responsibility for costs related to all required transmission and ancillary services. If Purchaser obtains the required transmission and ancillary services, APS shall file a service agreement with the FERC placing the Purchaser under APS' Open Access Transmission Tariff. All pertinent arrangements for such services can be made directly with APS' Transmission Group personnel at:

Arizona Public Service Company
P.O. Box 53999; Station 2260
Phoenix, Arizona 85072-3999
Facsimile No. (602) 250-1127

II. In the alternative, Purchaser may request that APS' Merchant Group secure all transmission and ancillary services under APS' Open Access Transmission Tariff required to effect service to Purchaser. APS' Merchant Group shall have the option to decline such requests.

Should the APS Merchant Group secure all transmission and related services, an appropriate Open Access Transmission Tariff Service Agreement shall be filed with the Federal Energy Regulatory Commission.

The unbundled rate components for each transmission and ancillary service assessed to the Purchaser for Power and/or Energy under this Electric Coordination Tariff No. 1 are listed on Attachment A.

[8] The Hourly Palo Verde Shaped Index shall be determined as shown on Table A.

APS-FERC Rate Schedule No. 225

Citizens Utilities Company

Conformed & Red-Lined Copy

SERVICE SCHEDULE A - WHOLESALE POWER
TO THE
POWER SERVICE AGREEMENT
BETWEEN
ARIZONA PUBLIC SERVICE COMPANY
AND
CITIZENS UTILITIES COMPANY

EXHIBIT B

DETERMINATION OF CEILING AND MINIMUM RATES APPLICABLE
TO SALE OF WHOLESALE POWER UNDER SERVICE SCHEDULE A

I. .Sales of Wholesale Power made by APS under the terms and conditions of Service Schedule A to the Wholesale Power Service Agreement shall be based on the costs of Palo Verde Unit No. 3. Citizens shall pay a charge not to exceed the following amounts to APS for power and energy supplied under Service Schedule A:

Maximum Demand Charge:[1]

Annual	$ 515.83/kW
Monthly	$ 42.99/kW
Weekly	$ 9.92/kW
Daily	$ 1.98/kW[2]
Hourly	$ 0.1238/kW[3]

plus

Energy Charge:

a) no less than 100% of APS' System Incremental Costs (SIC), plus

b) up to 10% of SIC[4]

Note A: The total charges for Power and Energy shall not exceed the product of the requested demand (kW) multiplied by the applicable Maximum Demand Charge in Section 1 above, plus the variable costs of Palo Verde Unit No. 3 (based on the second previous month's cost data), and not withstanding the foregoing, a floor equal to 100% of APS' System Incremental Cost.

Note B: The total amount of Power available for sales by APS under this Service Schedule and under other APS tariffs and agreements, for which the agreed upon demand charge is determined based on Palo Verde Unit No. 3, is limited to 370 MW(APS' share of Palo Verde No. 3) on an hourly basis.

II. The minimum charge for service under Service Schedule A shall be the SIC.

Provided, however, the monthly ceiling rate and monthly minimum rate as defined in parts I and II above, shall be the lesser of these rates: (i) developed utilizing the aggregate of APS' actual hourly SIC values during the month, or

[1] The Maximum Demand Charge for weekly, daily and hourly periods were computed utilizing the "AEP" methodology

[2] The Daily rate of $1.98/kW shall not exceed the product of the number of kilowatts sold for a week multiplied by the maximum weekly demand charge of $9.92/kW.

[3] The hourly rate of $0.1238/kW shall not exceed the product of the number of kilowatts sold for a day multiplied by the maximum daily demand charge of $1.98/kW, and also not exceed the product of the number of kilowatts sold for a week multiplied by the maximum weekly demand charge of $9.92kW.

[4] Whenever the SIC for an hour is based on Purchased Power, the 10% mark-up shall be limited to one mill/kWh.

(ii) the rates as developed utilizing the aggregate of hourly cents/kWh index in lieu of SIC. The hourly cents/kWh index shall be based on a Palo Verde Shaped Index[5].

III. Citizens shall also be responsible for purchased power costs, and for any other costs incurred by APS in fulfilling its obligations for power and energy under this Service Schedule A which otherwise would not have been incurred.

[5] The Hourly Palo Verde Shaped Index shall be determined as shown on Table A.

SERVICE SCHEDULE B
(SUPPLEMENTAL CAPACITY)
TO THE
POWER SERVICE AGREEMENT
BETWEEN
ARIZONA PUBLIC SERVICE COMPANY
AND
CITIZENS UTILITIES COMPANY

EXHIBIT A

DETERMINATION OF CEILING AND MINIMUM RATES APPLICABLE TO SALE OF SUPPLEMENTAL CAPACITY UNDER SERVICE SCHEDULE B.

I. Sales of Supplemental Capacity and related energy made by APS under the terms and conditions of Service Schedule B to the Wholesale Power Service Agreement from certain APS resources shall not exceed the following amounts:

Maximum Demand Charge:[1]

Annual	$105.77/kW
Monthly	$ 8.81/kW
Weekly	$ 2.03/kW
Daily	$ 0.41/kW[2]
Hourly	$ 0.0256/kW[3]

plus

Energy Charge:

a) no less than 100% of APS' System. Incremental Costs (SIC), plus
b) Up to 10% of SIC[4]

II. The minimum charge for service under Service Schedule B shall be the SIC.

Provided, however, the monthly ceiling rate and monthly minimum rate as defined in parts I and II above, shall be the lesser of these rates: (i) developed utilizing the aggregate of APS' actual hourly SIC values during the month, or (ii) the rates as developed utilizing the aggregate of hourly cents/kWh index in lieu of SIC. The hourly cents/kWh index shall be based on a Palo Verde Shaped Index[5].

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[1] The Maximum Demand Charge for weekly, daily and hourly periods were computed utilizing the "AEP" methodology.

[2] The Daily rate of $0.41/kW shall not exceed the product of the number of kilowatts sold for a week multiplied by the maximum weekly demand charge of $2.03/kW.

[3] The hourly rate of $0.0256/kW shall not exceed the product of the number of kilowatts sold for a day multiplied by the maximum daily demand charge of $0.41/kW, and also not exceed the product of the number of kilowatts sold for a week multiplied by the maximum weekly demand charge of $2.03kW.

[4] Whenever the SIC for an hour is based on Purchased Power, the 10% mark-up shall be limited to one mill/kWh.

[5] The Hourly Palo Verde Shaped Index shall be determined as shown on Table A.

III. Citizens shall also be responsible for purchased power costs, and for any other costs incurred by APS in fulfilling its obligations for supplemental capacity and energy under this Service Schedule B which otherwise would not have been incurred.

SERVICE SCHEDULE C - SUPPLEMENTAL PEAKING ENERGY
TO THE
POWER SERVICE AGREEMENT
BETWEEN
ARIZONA PUBLIC SERVICE COMPANY
AND
CITIZENS UTILITIES COMPANY

EXHIBIT A

DETERMINATION OF CEILING AND MINIMUM RATES APPLICABLE TO SALE OF SUPPLEMENTAL PEAKING ENERGY UNDER SERVICE SCHEDULE B

I. Sales of Supplemental Peaking Energy made by APS under the terms and conditions of Service Schedule C to the Wholesale Power Service Agreement from certain APS resources shall not exceed the following amounts:

Maximum Demand Charge:[1]

Annual	$ 105.77/kW
Monthly	$ 8.81/kW
Weekly	$ 2.03/kW
Daily	$ 0.41/kW[2]
Hourly	$ 0.0256/kW[3]

plus

Energy Charge:

a) no less than 100% of APS' System Incremental Costs (SIC), plus

b) up to 10% of SIC[4]

II. The minimum charge of service under Service Schedule C shall be the SIC.

Provided, however, the monthly ceiling rate and monthly minimum rate as defined in parts I and II above, shall be the lesser of these rates: (i) developed utilizing the aggregate of APS' actual hourly SIC values during the month, or (ii) the rates as developed utilizing the aggregate of hourly cents/kWh index in lieu of SIC. The hourly cents/kWh index shall be based on a Palo Verde Shaped Index[5].

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[1] The Maximum Demand Charge for weekly, daily and hourly periods were computed utilizing the "AEP" methodology.

[2] The Daily rate of $0.41/kW shall not exceed the product of the number of kilowatts sold for a week multiplied by the maximum weekly demand charge of $2.03/kW.

[3] The hourly rate of $0.0256/kW shall not exceed the product of the number of kilowatts sold for a day multiplied by the maximum daily demand charge of $0.41/kW, and also not exceed the product of the number of kilowatts sold for a week multiplied by the maximum weekly demand charge of $2.03kW.

[4] Whenever the SIC for an hour is based on Purchased Power, the 10% mark-up shall be limited to one mill/kWh.

[5] The Hourly Palo Verde Shaped Index shall be determined as shown on Table A.

III. Citizens shall also be responsible for purchased power costs, and for any other costs incurred by APS in fulfilling its obligations for supplemental peaking energy under this Service Schedule C which otherwise would not have been incurred.

EXAMPLE OF DETERMINATION OF THE PALO VERDE SHAPED INDEX

TABLE A

Date	ou	SP-15 (1) Index $/MWh	PV Index (2) Firm Price On Peak $/MWh	PV Index (2) Firm Price Off Peak $/MWh	PV Shaped Index (3) ($/MWh)	Date	Hou	SP-15 (1) Index $/MWh	PV Index (2) Firm Price On Peak $/MWh	PV Index (2) Firm Price Off Peak $/MWh	PV Shaped Index (3) ($/MWh)
9/1/1998	1	28.52		32.50	34.13	4/28/1999	1	14.50		14.88	14.43
9/1/1998	2	27.48		32.50	32.88	4/28/1999	2	13.50		14.88	13.44
9/1/1998	3	26.18		32.50	31.33	4/28/1999	3	11.52		14.88	11.47
9/1/1998	4	25.48		32.50	30.49	4/28/1999	4	11.65		14.88	11.60
9/1/1998	5	25.60		32.50	30.63	4/28/1999	5	12.00		14.88	11.94
9/1/1998	6	27.55		32.50	32.97	4/28/1999	6	15.49		14.88	15.42
9/1/1998	7	28.16	91.89		25.93	4/28/1999	7	24.32	26.85		22.67
9/1/1998	8	29.37	91.89		27.04	4/28/1999	8	31.50	26.85		29.37
9/1/1998	9	37.49	91.89		34.52	4/28/1999	9	30.59	26.85		28.52
9/1/1998	10	49.00	91.89		45.12	4/28/1999	10	30.99	26.85		28.89
9/1/1998	11	88.36	91.89		81.36	4/28/1999	11	29.71	26.85		27.70
9/1/1998	12	102.84	91.89		94.70	4/28/1999	12	28.99	26.85		27.03
9/1/1998	13	122.68	91.89		112.97	4/28/1999	13	28.49	26.85		26.56
9/1/1998	14	136.86	91.89		126.03	4/28/1999	14	28.00	26.85		26.10
9/1/1998	15	155.10	91.89		142.82	4/28/1999	15	27.49	26.85		25.63
9/1/1998	16	167.06	91.89		153.83	4/28/1999	16	26.89	26.85		25.07
9/1/1998	17	165.19	91.89		152.11	4/28/1999	17	26.84	26.85		25.02
9/1/1998	18	141.53	91.89		130.33	4/28/1999	18	26.75	26.85		24.94
9/1/1998	19	118.06	91.89		108.71	4/28/1999	19	26.28	26.85		24.50
9/1/1998	20	104.99	91.89		96.68	4/28/1999	20	29.50	26.85		27.50
9/1/1998	21	99.90	91.89		91.99	4/28/1999	21	35.00	26.85		32.63
9/1/1998	22	50.00	91.89		46.04	4/28/1999	22	29.50	26.85		27.50
9/1/1998	23	28.17		32.50	33.71	4/28/1999	23	23.64		14.88	23.53
9/1/1998	24	28.29		32.50	33.85	4/28/1999	24	17.32		14.88	17.24
Average for Day SP-15 on-peak			99.79	Avg PV Indx shaped onpk	91.89	Average for Day SP-15 on-peak			28.80	Avg PV Indx shaped onpk	26.85
Average for Day SP-15 off-peak			27.16	Avg PV Indx shaped offpk	32.50	Average for Day SP-15 off-peak			14.95	Avg PV Indx shaped offpk	14.88

NOTES: (1) California Power Exchange (CalPX) Day Ahead Hourly SP-15 Post Congestion Index ("SP-15"). Found on Website: www. CALPX.com. For specific instructions: Get on website:http://www.calpx.com/prices/index_prices_dayahead_trading.html Then select the "Hourly Zonal Prices Constrained Report" and the dates you want. (For this example select 9/1/98) Hit the "view" key. Scroll over to SP-15 (right side) and look at the price. It should be $28.52 for hour 1.

(2) Dow Jones Palo Verde Daily On and Off-Peak Index. This index can be found for three current months on website http://www.energyonline.com/Restructuring/energydb/estathme.html.

(3) The on-peak value of the Palo Verde Shaped Index is calculated by taking the ratio of the SP-15 Index hourly value on-peak divide it by the SP-15 average daily on-peak values, times the Palo Verde On-Peak value for the day. The off-peak value for PV Shaped Index is calculted using SP-15 off-peak values in the ratio times the PV off-peak value for the day. PV Index Shaped = SP-15 hourly value/SP15 Average of Daily Values X PV Index for same hour.

SERVICE SCHEDULE A - WHOLESALE POWER
TO THE
POWER SERVICE AGREEMENT
BETWEEN
ARIZONA PUBLIC SERVICE COMPANY
AND
CITIZENS UTILITIES COMPANY

EXHIBIT B

DETERMINATION OF CEILING AND MINIMUM RATES APPLICABLE
TO SALE OF WHOLESALE POWER UNDER SERVICE SCHEDULE A

I. .Sales of Wholesale Power made by APS under the terms and conditions of Service Schedule A to the Wholesale Power Service Agreement shall be based on the costs of Palo Verde Unit No. 3. Citizens shall pay a charge not to exceed the following amounts to APS for power and energy supplied under Service Schedule A:

Maximum Demand Charge:[1]

Annual	$ 515.83/kW
Monthly	$ 42.99/kW
Weekly	$ 9.92/kW
Daily	$ 1.98/kW[2]
Hourly	$ 0.1238/kW[3]

plus

Energy Charge:

a) no less than 100% of APS' System Incremental Costs (SIC), plus

b) up to 10% of SIC[4]

Note A: The total charges for Power and Energy shall not exceed the product of the requested demand (kW) multiplied by the applicable Maximum Demand Charge in Section 1 above, plus the variable costs of Palo Verde Unit No. 3 (based on the second previous month's cost data), and not withstanding the foregoing, a floor equal to 100% of APS' System Incremental Cost.

Note B: The total amount of Power available for sales by APS under this Service Schedule and under other APS tariffs and agreements, for which the agreed upon demand charge is determined based on Palo Verde Unit No. 3, is limited to 370 MW(APS' share of Palo Verde No. 3) on an hourly basis.

II. The minimum charge for service under Service Schedule A shall be the SIC.

Provided, however, the monthly ceiling rate and monthly minimum rate as defined in parts I and II above, shall be the lesser of these rates: (i) developed utilizing the aggregate of APS' actual hourly SIC values during the month, or

[1] The Maximum Demand Charge for weekly, daily and hourly periods were computed utilizing the "AEP" methodology

[2] The Daily rate of $1.98/kW shall not exceed the product of the number of kilowatts sold for a week multiplied by the maximum weekly demand charge of $9.92/kW.

[3] The hourly rate of $0.1238/kW shall not exceed the product of the number of kilowatts sold for a day multiplied by the maximum daily demand charge of $1.98/kW, and also not exceed the product of the number of kilowatts sold for a week multiplied by the maximum weekly demand charge of $9.92kW.

[4] Whenever the SIC for an hour is based on Purchased Power, the 10% mark-up shall be limited to one mill/kWh.

SERVICE SCHEDULE B
(SUPPLEMENTAL CAPACITY)
TO THE
POWER SERVICE AGREEMENT
BETWEEN
ARIZONA PUBLIC SERVICE COMPANY
AND
CITIZENS UTILITIES COMPANY

EXHIBIT A

DETERMINATION OF CEILING AND MINIMUM RATES APPLICABLE TO SALE OF SUPPLEMENTAL CAPACITY UNDER SERVICE SCHEDULE B.

I. Sales of Supplemental Capacity and related energy made by APS under the terms and conditions of Service Schedule B to the Wholesale Power Service Agreement from certain APS resources shall not exceed the following amounts:

Maximum Demand Charge:[1]

Annual	$105.77/kW
Monthly	$ 8.81/kW
Weekly	$ 2.03/kW
Daily	$ 0.41/kW[2]
Hourly	$ 0.0256/kW[3]

plus

Energy Charge:

a) no less than 100% of APS' System. Incremental Costs (SIC), plus
b) Up to 10% of SIC[4]

II. The minimum charge for service under Service Schedule B shall be the SIC.

Provided, however, the monthly ceiling rate and monthly minimum rate as defined in parts I and II above, shall be the lesser of these rates: (i) developed utilizing the aggregate of APS' actual hourly SIC values during the month, or (ii) the rates as developed utilizing the aggregate of hourly cents/kWh index in lieu of SIC. The hourly cents/kWh index shall be based on a Palo Verde Shaped Index[5].

---

[1] The Maximum Demand Charge for weekly, daily and hourly periods were computed utilizing the "AEP" methodology.

[2] The Daily rate of $0.41/kW shall not exceed the product of the number of kilowatts sold for a week multiplied by the maximum weekly demand charge of $2.03/kW.

[3] The hourly rate of $0.0256/kW shall not exceed the product of the number of kilowatts sold for a day multiplied by the maximum daily demand charge of $0.41/kW, and also not exceed the product of the number of kilowatts sold for a week multiplied by the maximum weekly demand charge of $2.03kW.

[4] Whenever the SIC for an hour is based on Purchased Power, the 10% mark-up shall be limited to one mill/kWh.

[5] The Hourly Palo Verde Shaped Index shall be determined as shown on Table A.

III. Citizens shall also be responsible for purchased power costs, and for any other costs incurred by APS in fulfilling its obligations for supplemental capacity and energy under this Service Schedule B which otherwise would not have been incurred.

SERVICE SCHEDULE C - SUPPLEMENTAL PEAKING ENERGY
TO THE
POWER SERVICE AGREEMENT
BETWEEN
ARIZONA PUBLIC SERVICE COMPANY
AND
CITIZENS UTILITIES COMPANY

EXHIBIT A

DETERMINATION OF CEILING AND MINIMUM RATES APPLICABLE TO SALE OF SUPPLEMENTAL PEAKING ENERGY UNDER SERVICE SCHEDULE B

I. Sales of Supplemental Peaking Energy made by APS under the terms and conditions of Service Schedule C to the Wholesale Power Service Agreement from certain APS resources shall not exceed the following amounts:

Maximum Demand Charge:[1]

Annual	$ 105.77/kW
Monthly	$ 8.81/kW
Weekly	$ 2.03/kW
Daily	$ 0.41/kW[2]
Hourly	$ 0.0256/kW[3]

plus

Energy Charge:

a) no less than 100% of APS' System Incremental Costs (SIC), plus

b) up to 10% of SIC[4]

II. The minimum charge of service under Service Schedule C shall be the SIC.

Provided, however, the monthly ceiling rate and monthly minimum rate as defined in parts I and II above, shall be the lesser of these rates: (i) developed utilizing the aggregate of APS' actual hourly SIC values during the month, or (ii) the rates as developed utilizing the aggregate of hourly cents/kWh index in lieu of SIC. The hourly cents/kWh index shall be based on a Palo Verde Shaped Index[5].

---

[1] The Maximum Demand Charge for weekly, daily and hourly periods were computed utilizing the "AEP" methodology.

[2] The Daily rate of $0.41/kW shall not exceed the product of the number of kilowatts sold for a week multiplied by the maximum weekly demand charge of $2.03/kW.

[3] The hourly rate of $0.0256/kW shall not exceed the product of the number of kilowatts sold for a day multiplied by the maximum daily demand charge of $0.41/kW, and also not exceed the product of the number of kilowatts sold for a week multiplied by the maximum weekly demand charge of $2.03kW.

[4] Whenever the SIC for an hour is based on Purchased Power, the 10% mark-up shall be limited to one mill/kWh.

[5] The Hourly Palo Verde Shaped Index shall be determined as shown on Table A.

III. Citizens shall also be responsible for purchased power costs, and for any other costs incurred by APS in fulfilling its obligations for supplemental peaking energy under this Service Schedule C which otherwise would not have been incurred.

EXAMPLE OF DETERMINATION OF THE PALO VERDE SHAPED INDEX

TABLE A

Date	ou	SP-15 (1) Index $/MWh	PV Index (2) Firm Price On Peak $/MWh	PV Index (2) Firm Price Off Peak $/MWh	PV Shaped Index (3) ($/MWh)	Date	Hou	SP-15 (1) Index $/MWh	PV Index (2) Firm Price On Peak $/MWh	PV Index (2) Firm Price Off Peak $/MWh	PV Shaped Index (3) ($/MWh)
9/1/1998	1	28.52		32.50	34.13	4/28/1999	1	14.50		14.88	14.43
9/1/1998	2	27.48		32.50	32.88	4/28/1999	2	13.50		14.88	13.44
9/1/1998	3	26.18		32.50	31.33	4/28/1999	3	11.52		14.88	11.47
9/1/1998	4	25.48		32.50	30.49	4/28/1999	4	11.65		14.88	11.60
9/1/1998	5	25.60		32.50	30.63	4/28/1999	5	12.00		14.88	11.94
9/1/1998	6	27.55		32.50	32.97	4/28/1999	6	15.49		14.88	15.42
9/1/1998	7	28.16	91.89		25.93	4/28/1999	7	24.32	26.85		22.67
9/1/1998	8	29.37	91.89		27.04	4/28/1999	8	31.50	26.85		29.37
9/1/1998	9	37.49	91.89		34.52	4/28/1999	9	30.59	26.85		28.52
9/1/1998	10	49.00	91.89		45.12	4/28/1999	10	30.99	26.85		28.89
9/1/1998	11	88.36	91.89		81.36	4/28/1999	11	29.71	26.85		27.70
9/1/1998	12	102.84	91.89		94.70	4/28/1999	12	28.99	26.85		27.03
9/1/1998	13	122.68	91.89		112.97	4/28/1999	13	28.49	26.85		26.56
9/1/1998	14	136.86	91.89		126.03	4/28/1999	14	28.00	26.85		26.10
9/1/1998	15	155.10	91.89		142.82	4/28/1999	15	27.49	26.85		25.63
9/1/1998	16	167.06	91.89		153.83	4/28/1999	16	26.89	26.85		25.07
9/1/1998	17	165.19	91.89		152.11	4/28/1999	17	26.84	26.85		25.02
9/1/1998	18	141.53	91.89		130.33	4/28/1999	18	26.75	26.85		24.94
9/1/1998	19	118.06	91.89		108.71	4/28/1999	19	26.28	26.85		24.50
9/1/1998	20	104.99	91.89		96.68	4/28/1999	20	29.50	26.85		27.50
9/1/1998	21	99.90	91.89		91.99	4/28/1999	21	35.00	26.85		32.63
9/1/1998	22	50.00	91.89		46.04	4/28/1999	22	29.50	26.85		27.50
9/1/1998	23	28.17		32.50	33.71	4/28/1999	23	23.64		14.88	23.53
9/1/1998	24	28.29		32.50	33.85	4/28/1999	24	17.32		14.88	17.24
Average for Day SP-15 on-peak			99.79	Avg PV Indx shaped onpk	91.89	Average for Day SP-15 on-peak			28.80	Avg PV Indx shaped onpk	26.85
Average for Day SP-15 off-peak			27.16	Avg PV Indx shaped offpk	32.50	Average for Day SP-15 off-peak			14.95	Avg PV Indx shaped offpk	14.88

NOTES: (1) California Power Exchange (CalPX) Day Ahead Hourly SP-15 Post Congestion Index ("SP-15"). Found on Website: www. CALPX.com. For specific instructions: Get on website:http://www.calpx.com/prices/index_prices_dayahead_trading.html Then select the "Hourly Zonal Prices Constrained Report" and the dates you want. (For this example select 9/1/98) Hit the "view" key. Scroll over to SP-15 (right side) and look at the price. It should be $28.52 for hour 1.

(2) Dow Jones Palo Verde Daily On and Off-Peak Index. This index can be found for three current months on website http://www.energyonline.com/Restructuring/energydb/estathme.html.

(3) The on-peak value of the Palo Verde Shaped Index is calculated by taking the ratio of the SP-15 Index hourly value on-peak divide it by the SP-15 average daily on-peak values, times the Palo Verde On-Peak value for the day. The off-peak value for PV Shaped Index is calculted using SP-15 off-peak values in the ratio times the PV off-peak value for the day. PV Index Shaped = SP-15 hourly value/SP15 Average of Daily Values X PV Index for same hour.

a) Maximum Demand Charge[4]:

Annual:	$ 94.21/kW
Monthly:	$ 7.85/kW
Weekly:	$ 1.81/kW
Daily:	$ 0.36/kW[5]
Hourly:	$ 0.0225/kW[6]

b) APS's actual purchased power costs; plus
c) a one mill adder

Provided, however, the monthly ceiling rate as defined in parts I and II-A above, shall be the lesser of this rate: (i) developed utilizing the aggregate of APS' actual hourly SIC values during the month, or (ii) the rate as developed utilizing the aggregate of hourly cents/kWh index in lieu of SIC. The hourly cents/kWh index shall be based on a Palo Verde Shaped Index[7].

II-B. When a sale of Power and/or Energy made by APS is conditioned upon APS acquiring purchased power for the explicit purpose of fulfilling APS's obligations for transactions hereunder and for which APS's system does not standby to supply Firm Power and Energy from its own resources, CRC shall pay the following amounts to APS for Power and Energy supplied under this Agreement:

a) APS's actual purchased power costs; plus
b) a transmission adder of 2.9 mills/kWh for use of APS's transmission system; plus
c) a one mill adder when such purchased power transactions are less than one year in duration.

III. For purposes of determining the maximum charge, CRC shall also be responsible for any taxes, purchased power costs, and for any other costs incurred by APS in fulfilling its obligations for Power and Energy under this Agreement which otherwise would not have been incurred.

Effective Date: _____

[4] The maximum demand charge for weekly, daily and hourly period were computed utilizing the "AEP" methodology.

[5] The daily rate of $0.36/KW shall not exceed the product of the number of kilowatts sold for a week multiplied by the maximum weekly demand charge of $1.81.

[6] The hourly rate of $0.0225/kW shall not exceed the product of the number of kilowatts sold for a day multiplied by the maximum daily demand charge of $0.36/kW, and also not exceed the product of the number of kilowatts sold for a week multiplied by the maximum weekly demand charge of $1.81/kW.

[7] The Hourly Palo Verde Shaped Index shall be determined as shown on Table A.

EXAMPLE OF DETERMINATION OF THE PALO VERDE SHAPED INDEX

TABLE A

Date	ou	SP-15 (1) Index $/MWh	PV Index (2) Firm Price On Peak $/MWh	PV Index (2) Firm Price Off Peak $/MWh	PV Shaped Index (3) ($/MWh)
9/1/1998	1	28.52		32.50	34.13
9/1/1998	2	27.48		32.50	32.88
9/1/1998	3	26.18		32.50	31.33
9/1/1998	4	25.48		32.50	30.49
9/1/1998	5	25.60		32.50	30.63
9/1/1998	6	27.55		32.50	32.97
9/1/1998	7	28.16	91.89		25.93
9/1/1998	8	29.37	91.89		27.04
9/1/1998	9	37.49	91.89		34.52
9/1/1998	10	49.00	91.89		45.12
9/1/1998	11	88.36	91.89		81.36
9/1/1998	12	102.84	91.89		94.70
9/1/1998	13	122.68	91.89		112.97
9/1/1998	14	136.86	91.89		126.03
9/1/1998	15	155.10	91.89		142.82
9/1/1998	16	167.06	91.89		153.83
9/1/1998	17	165.19	91.89		152.11
9/1/1998	18	141.53	91.89		130.33
9/1/1998	19	118.06	91.89		108.71
9/1/1998	20	104.99	91.89		96.68
9/1/1998	21	99.90	91.89		91.99
9/1/1998	22	50.00	91.89		46.04
9/1/1998	23	28.17		32.50	33.71
9/1/1998	24	28.29		32.50	33.85
Average for Day SP-15 on-peak			99.79	Avg PV Indx shaped onpk	91.89
Average for Day SP-15 off-peak			27.16	Avg PV Indx shaped offpk	32.50

Date	Hou	SP-15 (1) Index $/MWh	PV Index (2) Firm Price On Peak $/MWh	PV Index (2) Firm Price Off Peak $/MWh	PV Shaped Index (3) ($/MWh)
4/28/1999	1	14.50		14.88	14.43
4/28/1999	2	13.50		14.88	13.44
4/28/1999	3	11.52		14.88	11.47
4/28/1999	4	11.65		14.88	11.60
4/28/1999	5	12.00		14.88	11.94
4/28/1999	6	15.49		14.88	15.42
4/28/1999	7	24.32	26.85		22.67
4/28/1999	8	31.50	26.85		29.37
4/28/1999	9	30.59	26.85		28.52
4/28/1999	10	30.99	26.85		28.89
4/28/1999	11	29.71	26.85		27.70
4/28/1999	12	28.99	26.85		27.03
4/28/1999	13	28.49	26.85		26.56
4/28/1999	14	28.00	26.85		26.10
4/28/1999	15	27.49	26.85		25.63
4/28/1999	16	26.89	26.85		25.07
4/28/1999	17	26.84	26.85		25.02
4/28/1999	18	26.75	26.85		24.94
4/28/1999	19	26.28	26.85		24.50
4/28/1999	20	29.50	26.85		27.50
4/28/1999	21	35.00	26.85		32.63
4/28/1999	22	29.50	26.85		27.50
4/28/1999	23	23.64		14.88	23.53
4/28/1999	24	17.32		14.88	17.24
Average for Day SP-15 on-peak			28.80	Avg PV Indx shaped onpk	26.85
Average for Day SP-15 off-peak			14.95	Avg PV Indx shaped offpk	14.88

NOTES: (1) California Power Exchange (CalPX) Day Ahead Hourly SP-15 Post Congestion Index ("SP-15"). Found on Website: www. CALPX.com. For specific instructions: Get on website:http://www.calpx.com/prices/index_prices_dayahead_trading.html Then select the "Hourly Zonal Prices Constrained Report" and the dates you want. (For this example select 9/1/98) Hit the "view" key. Scroll over to SP-15 (right side) and look at the price. It should be $28.52 for hour 1.

(2) Dow Jones Palo Verde Daily On and Off-Peak Index. This index can be found for three current months on website http://www.energyonline.com/Restructuring/energydb/estathme.html.

(3) The on-peak value of the Palo Verde Shaped Index is calculated by taking the ratio of the SP-15 Index hourly value on-peak divide it by the SP-15 average daily on-peak values, times the Palo Verde On-Peak value for the day. The off-peak value for PV Shaped Index is calculted using SP-15 off-peak values in the ratio times the PV off-peak value for the day. PV Index Shaped = SP-15 hourly value/SP15 Average of Daily Values X PV Index for same hour.

ELECTRIC POWER SERVICE AGREEMENT
BETWEEN
COLORADO RIVER COMMISSION OF NEVADA
AND
APS

EXHIBIT B

Determination of Maximum Charges Applicable to the Sale of Power and Energy to CRC.

I. For sales of Power and Energy made by APS to CRC from certain APS resources, CRC shall pay a charge not to exceed the following amounts:

Maximum Demand Charge[1]:

Annual:	$ 94.21/kW
Monthly:	$ 7.85/kW
Weekly:	$ 1.81/kW
Daily:	$ 0.36/kW[2]
Hourly:	$ 0.0225/kW[3]; plus

Energy Charge:

a) 100% of APS's System Incremental Costs (SIC); plus
b) up to 10% of SIC

II-A. When APS purchases Power and/or Energy from other entities for economic purposes to fulfill its system obligations, and should such purchases(s) subsequently be determined to be the basis for determination of the SIC for transactions under this Agreement for which APS stands ready to supply Power and Energy from its own resources, CRC shall pay a charge not to exceed the following amounts to APS for Power and Energy supplied under this Agreement:

[1] The maximum demand charge for weekly, daily and hourly period were computed utilizing the "AEP" methodology.

[2] The daily rate of $0.36/kW shall not exceed the product of the number of kilowatts sold for a week multiplied by the maximum weekly demand charge of $1.81/kW.

[3] The hourly rate of $0.0225/kW shall not exceed the product of the number of kilowatts sold for a day multiplied by the maximum daily demand charge of $0.36/kW, and also not exceed the product of the number of kilowatts sold for a week multiplied by the maximum weekly demand charge of $1.81/kW.

a) Maximum Demand Charge[4]:

Annual:	$ 94.21/kW
Monthly:	$ 7.85/kW
Weekly:	$ 1.81/kW
Daily:	$ 0.36/kW[5]
Hourly:	$ 0.0225/kW[6]

b) APS's actual purchased power costs; plus
c) a one mill adder

Provided, however, the monthly ceiling rate as defined in parts I and II-A above, shall be the lesser of this rate: (i) developed utilizing the aggregate of APS' actual hourly SIC values during the month, or (ii) the rate as developed utilizing the aggregate of hourly cents/kWh index in lieu of SIC. The hourly cents/kWh index shall be based on a Palo Verde Shaped Index[7].

II-B. When a sale of Power and/or Energy made by APS is conditioned upon APS acquiring purchased power for the explicit purpose of fulfilling APS's obligations for transactions hereunder and for which APS's system does not standby to supply Firm Power and Energy from its own resources, CRC shall pay the following amounts to APS for Power and Energy supplied under this Agreement:

a) APS's actual purchased power costs; plus
b) a transmission adder of 2.9 mills/kWh for use of APS's transmission system; plus
c) a one mill adder when such purchased power transactions are less than one year in duration.

III. For purposes of determining the maximum charge, CRC shall also be responsible for any taxes, purchased power costs, and for any other costs incurred by APS in fulfilling its obligations for Power and Energy under this Agreement which otherwise would not have been incurred.

Effective Date: _____

[4] The maximum demand charge for weekly, daily and hourly period were computed utilizing the "AEP" methodology.

[5] The daily rate of $0.36/KW shall not exceed the product of the number of kilowatts sold for a week multiplied by the maximum weekly demand charge of $1.81.

[6] The hourly rate of $0.0225/kW shall not exceed the product of the number of kilowatts sold for a day multiplied by the maximum daily demand charge of $0.36/kW, and also not exceed the product of the number of kilowatts sold for a week multiplied by the maximum weekly demand charge of $1.81/kW.

[7] The Hourly Palo Verde Shaped Index shall be determined as shown on Table A.

EXAMPLE OF DETERMINATION OF THE PALO VERDE SHAPED INDEX

TABLE A

Date	ou	SP-15 (1) Index $/MWh	PV Index (2) Firm Price On Peak $/MWh	PV Index (2) Firm Price Off Peak $/MWh	PV Shaped Index (3) ($/MWh)
9/1/1998	1	28.52		32.50	34.13
9/1/1998	2	27.48		32.50	32.88
9/1/1998	3	26.18		32.50	31.33
9/1/1998	4	25.48		32.50	30.49
9/1/1998	5	25.60		32.50	30.63
9/1/1998	6	27.55		32.50	32.97
9/1/1998	7	28.16	91.89		25.93
9/1/1998	8	29.37	91.89		27.04
9/1/1998	9	37.49	91.89		34.52
9/1/1998	10	49.00	91.89		45.12
9/1/1998	11	88.36	91.89		81.36
9/1/1998	12	102.84	91.89		94.70
9/1/1998	13	122.68	91.89		112.97
9/1/1998	14	136.86	91.89		126.03
9/1/1998	15	155.10	91.89		142.82
9/1/1998	16	167.06	91.89		153.83
9/1/1998	17	165.19	91.89		152.11
9/1/1998	18	141.53	91.89		130.33
9/1/1998	19	118.06	91.89		108.71
9/1/1998	20	104.99	91.89		96.68
9/1/1998	21	99.90	91.89		91.99
9/1/1998	22	50.00	91.89		46.04
9/1/1998	23	28.17		32.50	33.71
9/1/1998	24	28.29		32.50	33.85
Average for Day SP-15 on-peak			99.79	Avg PV Indx shaped onpk	91.89
Average for Day SP-15 off-peak			27.16	Avg PV Indx shaped offpk	32.50

Date	Hou	SP-15 (1) Index $/MWh	PV Index (2) Firm Price On Peak $/MWh	PV Index (2) Firm Price Off Peak $/MWh	PV Shaped Index (3) ($/MWh)
4/28/1999	1	14.50		14.88	14.43
4/28/1999	2	13.50		14.88	13.44
4/28/1999	3	11.52		14.88	11.47
4/28/1999	4	11.65		14.88	11.60
4/28/1999	5	12.00		14.88	11.94
4/28/1999	6	15.49		14.88	15.42
4/28/1999	7	24.32	26.85		22.67
4/28/1999	8	31.50	26.85		29.37
4/28/1999	9	30.59	26.85		28.52
4/28/1999	10	30.99	26.85		28.89
4/28/1999	11	29.71	26.85		27.70
4/28/1999	12	28.99	26.85		27.03
4/28/1999	13	28.49	26.85		26.56
4/28/1999	14	28.00	26.85		26.10
4/28/1999	15	27.49	26.85		25.63
4/28/1999	16	26.89	26.85		25.07
4/28/1999	17	26.84	26.85		25.02
4/28/1999	18	26.75	26.85		24.94
4/28/1999	19	26.28	26.85		24.50
4/28/1999	20	29.50	26.85		27.50
4/28/1999	21	35.00	26.85		32.63
4/28/1999	22	29.50	26.85		27.50
4/28/1999	23	23.64		14.88	23.53
4/28/1999	24	17.32		14.88	17.24
Average for Day SP-15 on-peak			28.80	Avg PV Indx shaped onpk	26.85
Average for Day SP-15 off-peak			14.95	Avg PV Indx shaped offpk	14.88

NOTES: (1) California Power Exchange (CalPX) Day Ahead Hourly SP-15 Post Congestion Index ("SP-15"). Found on Website: www. CALPX.com. For specific instructions: Get on website:http://www.calpx.com/prices/index_prices_dayahead_trading.html Then select the "Hourly Zonal Prices Constrained Report" and the dates you want. (For this example select 9/1/98) Hit the "view" key. Scroll over to SP-15 (right side) and look at the price. It should be $28.52 for hour 1.

(2) Dow Jones Palo Verde Daily On and Off-Peak Index. This index can be found for three current months on website http://www.energyonline.com/Restructuring/energydb/estathme.html.

(3) The on-peak value of the Palo Verde Shaped Index is calculated by taking the ratio of the SP-15 Index hourly value on-peak divide it by the SP-15 average daily on-peak values, times the Palo Verde On-Peak value for the day. The off-peak value for PV Shaped Index is calculted using SP-15 off-peak values in the ratio times the PV off-peak value for the day. PV Index Shaped = SP-15 hourly value/SP15 Average of Daily Values X PV Index for same hour.

Service Agreement under APS' Market Rate Tariff

Tohono O'odham Utility Authority

Conformed & Red-Lined Copy

Exhibit I

RATES FOR POWER SUPPLY

The following rates and charges shall be applicable to Customer for the services provided under this Supplement No. 1. Customer shall pay Company monthly for such services in accordance with the following rate provisions:

1. Base Monthly Rate

   1.1 Customer Charge: $417/month per month, plus

   1.2 Demand Charge: $12.00/kW times the Monthly Billing Demand, Plus

   1.3 Energy Charge: Higher of (i) $0.0210 per kWh, or
   (ii) SIC per hour

   Provided, however, that the monthly energy charge as defined above shall be the lesser of this charge: (i) developed utilizing the aggregate of APS actual hourly SIC values during the month, or (ii) the rate as developed utilizing an aggregate of an hourly cents/kWh index in lieu of SIC. The hourly cents/kWh index shall be based on a Palo Verde Shaped Index[1].

2. Base Monthly Minimum:

   2.1 Customer Charge, plus

   2.2 Demand Charge

3. Determination of Monthly Billing Demand and Monthly Billing Energy:

   3.1 Monthly Billing Demand: The Monthly Billing Demand shall be the higher of:

   3.1.1 The applicable Contract Demand, or

   3.1.2 The demand determined by using the formula:

$$APSKW = HMKW - (HKW + PDKW)$$

   Where:

   APSKW = The highest 60-minute integrated demand kW provided by Company to Customer during the billing month at the Point of Delivery, plus Transmission Losses. In no event shall this amount be less than zero.

   HMKW = The highest integrated metered demand at the Point of Delivery during any 60-minute period of the billing month.

   HKW = The highest Hoover Resource kW utilized by Customer at the Point of Delivery during the applicable billing month.

   PDKW = The highest P-D Resource kW utilized by the Customer at the Point of Delivery during the applicable billing month.

[1] Hourly Palo Verde Shaped Index shall be determined as shown on Table A.

3.2 Monthly Billing Energy: The Monthly Billing Energy shall be determined as follows:

APSKWH = TKWH - (HKWH + PDKWH + FKWH)

Where:

APSKWH = The Monthly Billing Energy provided by Company to Customer at the Point of Delivery, plus Transmission Losses during the current billing month, however in no event shall this amount be less than zero.

TKWH = The total number of kWh delivered and metered at the Point of Delivery during the applicable billing month.

HKWH = The Hoover Resource kWh utilized by the Customer at the Point of Delivery during the applicable billing month.

PDKWH = The P-D kWh utilized by the Customer at the Point of Delivery during the applicable billing month.

FKWH = The total Firming Energy kWh utilized by Customer at the Point of Delivery during the applicable billing month.

4. Charges for Transmission Service:

The APS Merchant Group has executed a Service Agreement for Network Integration Transmission Service ("Network Service") under Part III of APS' Open Access Transmission Tariff ("OATT") on file with the Commission in order to effect delivery of power and energy pursuant to this transaction. The cost associated with the Transmission Service and all applicable ancillary services shall be absorbed by APS' Merchant Group and are subsumed within the charges for the Base Monthly Rate in Section 1 hereof.

The monthly demand charge for Network Service shall be calculated in accordance with Sections 34.1, 34.2 and 34.3 (See Attachment 1) of APS' OATT and the Annual Transmission Revenue Requirements specified in Attachment H thereto (See Attachment 2). Ancillary services shall be calculated monthly in accordance with Schedules 1, 2, 3, 5 and 6 of the OATT (see Attachments 3, 4, 5, 6 and 7).

ARIZONA PUBLIC SERVICE COMPANY	TOHONO O'ODHAM UTILITY AUTHORITY
Signature: _____	Signature: _____
Name: _____	Name: _____
Title: _____	Title: _____
Date: _____	Date: _____

Effective: Effective Billing Date

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4/28/1999	18	26.75	26.85		24.94
4/28/1999	19	26.28	26.85		24.50
4/28/1999	20	29.50	26.85		27.50
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(3) The on-peak value of the Palo Verde Shaped Index is calculated by taking the ratio of the SP-15 Index hourly value on-peak divide it by the SP-15 average daily on-peak values, times the Palo Verde On-Peak value for the day. The off-peak value for PV Shaped Index is calculted using SP-15 off-peak values in the ratio times the PV off-peak value for the day. PV Index Shaped = SP-15 hourly value/SP15 Average of Daily Values X PV Index for same hour.

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   1.3 Energy Charge: Higher of (i) $0.0210 per kWh, or
   (ii) SIC per hour

   Provided, however, that the monthly energy charge as defined above shall be the lesser of this charge: (i) developed utilizing the aggregate of APS actual hourly SIC values during the month, or (ii) the rate as developed utilizing an aggregate of an hourly cents/kWh index in lieu of SIC. The hourly cents/kWh index shall be based on a Palo Verde Shaped Index[1].

2. Base Monthly Minimum:

   2.1 Customer Charge, plus

   2.2 Demand Charge

3. Determination of Monthly Billing Demand and Monthly Billing Energy:

   3.1 Monthly Billing Demand: The Monthly Billing Demand shall be the higher of:

   3.1.1 The applicable Contract Demand, or

   3.1.2 The demand determined by using the formula:

   APSKW = HMKW - (HKW + PDKW)

   Where:

   APSKW = The highest 60-minute integrated demand kW provided by Company to Customer during the billing month at the Point of Delivery, plus Transmission Losses. In no event shall this amount be less than zero.

   HMKW = The highest integrated metered demand at the Point of Delivery during any 60-minute period of the billing month.

   HKW = The highest Hoover Resource kW utilized by Customer at the Point of Delivery during the applicable billing month.

   PDKW = The highest P-D Resource kW utilized by the Customer at the Point of Delivery during the applicable billing month.

[1] Hourly Palo Verde Shaped Index shall be determined as shown on Table A.

3.2 Monthly Billing Energy: The Monthly Billing Energy shall be determined as follows:

APSKWH = TKWH - (HKWH + PDKWH + FKWH)

Where:

APSKWH = The Monthly Billing Energy provided by Company to Customer at the Point of Delivery, plus Transmission Losses during the current billing month, however in no event shall this amount be less than zero.

TKWH = The total number of kWh delivered and metered at the Point of Delivery during the applicable billing month.

HKWH = The Hoover Resource kWh utilized by the Customer at the Point of Delivery during the applicable billing month.

PDKWH = The P-D kWh utilized by the Customer at the Point of Delivery during the applicable billing month.

FKWH = The total Firming Energy kWh utilized by Customer at the Point of Delivery during the applicable billing month.

4. Charges for Transmission Service:

The APS Merchant Group has executed a Service Agreement for Network Integration Transmission Service ("Network Service") under Part III of APS' Open Access Transmission Tariff ("OATT") on file with the Commission in order to effect delivery of power and energy pursuant to this transaction. The cost associated with the Transmission Service and all applicable ancillary services shall be absorbed by APS' Merchant Group and are subsumed within the charges for the Base Monthly Rate in Section 1 hereof.

The monthly demand charge for Network Service shall be calculated in accordance with Sections 34.1, 34.2 and 34.3 (See Attachment 1) of APS' OATT and the Annual Transmission Revenue Requirements specified in Attachment H thereto (See Attachment 2). Ancillary services shall be calculated monthly in accordance with Schedules 1, 2, 3, 5 and 6 of the OATT (see Attachments 3, 4, 5, 6 and 7).

ARIZONA PUBLIC SERVICE COMPANY	TOHONO O'ODHAM UTILITY AUTHORITY
Signature: _____	Signature: _____
Name: _____	Name: _____
Title: _____	Title: _____
Date: _____	Date: _____

Effective: Effective Billing Date

Exhibit E1

Revisions to Fuel Adjustment Clauses
in APS Wholesale Power Contracts:

Electrical District No. 3 (APS-FERC Rate Schedule No. 12)
Electrical District No. 1 (APS-FERC Rate Schedule No. 68)
Southern California Edison (APS-FERC Rate Schedule No. 120)
San Carlos Irrigation Project (APS-FERC Rate Schedule No. 201)

Revisions to Fuel Adjustment Clauses
in APS Market Rate Tariff Service Agreements:

Majority Districts
City of Wickenburg

Includes Conformed and Red-Lined Copies

NOTE: Exhibits I(A) and I(B) of each of the contracts or service agreements listed above are identical (in their original form and as revised). Applicants propose to add a new Exhibit I(C) to each of the contracts.

EXHIBIT I(A)

FUEL COST ADJUSTMENT CLAUSE

(1) The billing[1/] for service rendered during the billing month shall be increased or decreased by an adjustment amount per kilowatthour of sales (to the nearest 0.0001¢) equal to the difference between the fuel cost per kilowatthour of sales for that month and the base period, calculated as follows:

$$Adjustment\ Factor = \frac{F}{S} - 1.2438\ ¢/kWh$$

Where: "F" is the expense of fossil and nuclear fuel and certain purchased power costs in the current period and "S" is the kWh sales in the current period, as defined below.

(i) The applicable corrected monthly fuel adjustment factor for any given month shall be capped at a level that is no greater than the average of the actual corrected fuel adjustment factor for the same month for 1998 and 1999.

The calculation of the applicable monthly "Hold Harmless" corrected fuel adjustment factor shall be performed in accordance with Exhibit I(C).

(2) Fuel and purchased power costs (F) shall be the cost of:

(i) Fossil and nuclear fuel consumed in the Company's own plants, and the Company's share of fossil and nuclear fuel consumed in jointly owned or leased plants; plus

(ii) the actual identifiable fossil and nuclear fuel costs associated with energy purchased for reasons other than identified in paragraph (2)(iii) below; plus

(iii) the net energy cost of energy purchases, exclusive of capacity or demand charges (irrespective of the designation assigned to such transactions) when such energy is purchased on an economic dispatch basis. Included therein may be such costs as the charges for economy energy purchases and the charges as a result of scheduled outage, all such kinds of energy being purchased by the Company to substitute for its own higher cost energy; and less

(iv) the cost of fossil and nuclear fuel recovered through all inter-system sales and specific deliveries[2/]; plus

(v) a credit to allowable fuel and purchase power costs which passes to jurisdictional customers 75% of the benefits of sales transactions made under the aegis of the Conformed Western Systems Power Pool Agreement. Such credit shall be calculated in accordance with Exhibit I(B).

[1/] Billing under this clause will preliminarily be based on the billing month's sales multiplied by the adjustment factor determined from the second preceding month. The billing thus determined will be corrected to the adjustment factor determined for the billing month. Such correction will be made two months after the preliminary billing.

[2/] Specific deliveries are intended to include transactions for which the rate is tied to fuel costs of specific plants or units.

(3) Sales (S) shall be all kWh's sold, excluding inter-system sales and specific deliveries. Where for any reason, billed system sales cannot be coordinated with fuel costs for the billing period, sales may be equated to the sum of (i) generation, (ii) firm purchases, (iii) economy purchases, less (iv) energy associated with pumped storage operations, less (v) inter-system sales referred to in paragraph (2)(iv) above, less (vi) total system losses.

(4) The adjustment factor developed according to this procedure shall be modified to properly allow for losses (estimated if necessary) associated only with wholesale sales for resale.

(5) The adjustment factor developed according to this procedure may be further modified to allow the recovery of gross receipts and other similar revenue based tax charges occasioned by the fuel adjustment revenues.

(6) (a) The cost of fossil fuel shall include those items listed in Account 151 of the Commission's Uniform System of Accounts for Public Utilities and Licenses. The cost of nuclear fuel shall be that as shown in Account 518, except that if Account 518 also contains any expense for fossil fuel which has already been included in the cost of fossil fuel, it shall be deducted from this account. (Paragraph C of Account 518 includes the cost of other fuels used for ancillary steam facilities.)

(b) The cost of both fossil fuel and nuclear fuel shall also reflect all refunds and credits (including any applicable interest) not in excess of $25,000 for the FERC jurisdictional allocation of any single refund/credit received from fuel suppliers/vendors applicable to previous period (non-current) payments made to such suppliers/vendors for fuel or other related allowable expenses. If such refunds/credits are not passed through and credited to applicable fuel accounts for more than one billing cycle after the Company's receipt of such refunds/credits, the Company shall include an appropriate interest credit computed in accordance with 18 C.F.R. §35.19(a).

(7) Notwithstanding the specified aforementioned treatment of fuel and purchased power costs for purposes of inclusion in determining the Company's monthly Fuel Cost Adjustment Clause (FAC) factor, the following specific credits/debits to Account 518 (nuclear fuel expenses) related to Spent Nuclear Fuel Disposal Cost refunds received from the United States Department of Energy covering the period October, 1986 through January, 1994 shall be allowed for inclusion in computing applicable monthly FAC factors:

10/86	($2,232)	07/91	($80,234)
07/88	($5,526)	08/81	($69,045)
10/88	($15,534)	09/91	($64,688)
10/89	($18,970)	10/91	($59,390)
12/90	($2,175,153)	11/91	($39,207)
01/91	($63,884)	12/91	$550,519
02/91	($59,363)	02/92	($147,600)
03/91	($63,981)	06/92	$11,136
04/91	($52,520)	07/92	($543,312)
05/91	($54,089)	01/94	$381,252
06/91	($69,544)		

(8) Additionally, credits to Accounts 501, 547, and 555 related to refunds received from El Paso Natural Gas Company as a result of FERC Docket Nos. RP90-81-000, RP91-26-000, RP91-188-000, and RP92-60-000 shall be allowed for inclusion in computing applicable monthly FAC factors. In the aggregate, such credits covering the period March 1990 through July 1994 are in the amount of ($1,168,468).

EXHIBIT I(B)

SAMPLE
COMPUTATION OF WSPP CREDIT
FOR INCLUSION IN FERC FUEL ADJUSTMENT

MONTH OF: _____

Economy Sales/
Unit Commitment Sales/
System Capacity Sales:

Customer	(1) Total Sales Revenue ($)	(2) Fuel Cost ($)	(3) Wheeling Cost/1/ ($)	(4) Markup Col (1) - Col (2) - Col (3)
LADWP	23,150	17,703	106	5,341
NPC	4,250	3,213	65	972
SCE	217,914	161,272	1,047	55,595
SDG&E	45,788	29,351	250	16,187
SMUD	126,338	88,257	678	37,403
TOTAL SALES				115,498
				X 75%
AMOUNT TO BE CREDITED TO FUEL ADJUSTMENT				86,624

/1/ Reflects only those wheeling costs incurred by APS.

EXHIBIT I(B)

SAMPLE
COMPUTATION OF WSPP CREDIT
FOR INCLUSION IN FERC FUEL ADJUSTMENT

MONTH OF: _____

Economy Sales/
Unit Commitment Sales/
System Capacity Sales:

Customer	(1) Total Sales Revenue ($)	(2) Fuel Cost ($)	(3) Wheeling Cost/1/ ($)	(4) Markup Col (1) - Col (2) - Col (3)
LADWP	23,150	17,703	106	5,341
NPC	4,250	3,213	65	972
SCE	217,914	161,272	1,047	55,595
SDG&E	45,788	29,351	250	16,187
SMUD	126,338	88,257	678	37,403
TOTAL SALES				115,498
				X 75%
	AMOUNT TO BE CREDITED TO FUEL ADJUSTMENT			86,624

/1/ Reflects only those wheeling costs incurred by APS.

EXHIBIT I(C)

Arizona Public Service Company
Fuel Cost Adjustment Clause "Hold" Harmless" Calculation

Table 1
Calculation of APS' "Hold Harmless" Factor

(¢/kWh)

	(1) Actual Corrected 1998 FAC Factor	(2) Actual Corrected 1999 FAC Factor	(3) Average [Col (1) + Col (2)]/2
Jan	(0.4070)	(0.2499)	(0.3285)
Feb	(0.5574)	(0.2742)	(0.4158)
Mar	(0.4778)	(0.3406)	(0.4092)
Apr	(0.1669)	(0.1768)	(0.1719)
May	(0.2402)	(0.2493)	(0.2448)
June	(0.2550)	(0.1948)	(0.2249)
July	0.1298	(0.1891)	(0.0297)
Aug	0.2997	(0.4918)	(0.0961)
Sept	0.2254	(0.2361)	(0.0053)
Oct	(0.3159)	0.0378	(0.1391)
Nov	(0.4186)	(0.1469)	(0.2828)
Dec	(0.1622)		

Table 2
Examples Showing Determination of the Applicable Monthly Corrected FAC Factor
(January 2000)
For Illustrative Purposes Only

Example A:

(¢/kWh)

(1) Preliminary FAC Factor	(2) Calculated Correction FAC Factor	(3) Actual Corrected FAC Factor Col (1) + Col (2)	(4) "Hold Harmless" Factor From Table 1	(5) Applicable FAC Factor[1]
(0.1948)	(0.2970)	(0.4918)	(0.3285)	(0.4918)

Example B:

(¢/kWh)

(1) Preliminary FAC Factor	(2) Calculated Correction FAC Factor	(3) Actual Corrected FAC Factor Col (1) + Col (2)	(4) "Hold Harmless" Factor From Table 1	(5) Applicable FAC Factor[2]
0.0246	0.1002	0.1248	(0.3285)	(0.3285)

[1] This Applicable FAC factor shall always be the lesser of the value in either Column 3 or Column 4.
[2] This Applicable FAC factor shall always be the lesser of the value in either Column 3 or Column 4.

Exhibit E2

Revisions to Fuel Adjustment Clauses
in APS Wholesale Power Contract:

City of Williams (APS-FERC Rate Schedule No. 192)
Exhibit IV(A), Exhibit IV(B), and a new Exhibit IV(C)

Includes Conformed & Red-Lined Copies

EXHIBIT IV(A)

FUEL COST ADJUSTMENT CLAUSE

(1) The billing[1/] for service rendered during the billing month shall be increased or decreased by an adjustment amount per kilowatthour of sales (to the nearest 0.0001¢) equal to the difference between the fuel cost per kilowatthour of sales for that month and the base period, calculated as follows:

$$Adjustment\ Factor = \frac{F}{S} - 1.2438\ ¢/\text{kWh}$$

Where: "F" is the expense of fossil and nuclear fuel and certain purchased power costs in the current period and "S" is the kWh sales in the current period, as defined below.

(i) The applicable corrected monthly fuel adjustment factor for any given month shall be capped at a level that is no greater than the average of the actual corrected fuel adjustment factor for the same month for 1998 and 1999.

The calculation of the applicable monthly "Hold Harmless" corrected fuel adjustment factor shall be performed in accordance with Exhibit IV(C).

(2) Fuel and purchased power costs (F) shall be the cost of:

(i) Fossil and nuclear fuel consumed in the Company's own plants, and the Company's share of fossil and nuclear fuel consumed in jointly owned or leased plants; plus

(ii) the actual identifiable fossil and nuclear fuel costs associated with energy purchased for reasons other than identified in paragraph (2)(iii) below; plus

(iii) the net energy cost of energy purchases, exclusive of capacity or demand charges (irrespective of the designation assigned to such transactions) when such energy is purchased on an economic dispatch basis. Included therein may be such costs as the charges for economy energy purchases and the charges as a result of scheduled outage, all such kinds of energy being purchased by the Company to substitute for its own higher cost energy; and less

(iv) the cost of fossil and nuclear fuel recovered through all inter-system sales and specific deliveries[2/]; plus

(v) a credit to allowable fuel and purchase power costs which passes to jurisdictional customers 75% of the benefits of sales transactions made under the aegis of the Conformed Western Systems Power Pool Agreement. Such credit shall be calculated in accordance with Exhibit I(B).

[1/] Billing under this clause will preliminarily be based on the billing month's sales multiplied by the adjustment factor determined from the second preceding month. The billing thus determined will be corrected to the adjustment factor determined for the billing month. Such correction will be made two months after the preliminary billing.

[2/] Specific deliveries are intended to include transactions for which the rate is tied to fuel costs of specific plants or units.

(3) Sales (S) shall be all kWh's sold, excluding inter-system sales and specific deliveries. Where for any reason, billed system sales cannot be coordinated with fuel costs for the billing period, sales may be equated to the sum of (i) generation, (ii) firm purchases, (iii) economy purchases, less (iv) energy associated with pumped storage operations, less (v) inter-system sales referred to in paragraph (2)(iv) above, less (vi) total system losses.

(4) The adjustment factor developed according to this procedure shall be modified to properly allow for losses (estimated if necessary) associated only with wholesale sales for resale.

(5) The adjustment factor developed according to this procedure may be further modified to allow the recovery of gross receipts and other similar revenue based tax charges occasioned by the fuel adjustment revenues.

(6) (a) The cost of fossil fuel shall include those items listed in Account 151 of the Commission's Uniform System of Accounts for Public Utilities and Licenses. The cost of nuclear fuel shall be that as shown in Account 518, except that if Account 518 also contains any expense for fossil fuel which has already been included in the cost of fossil fuel, it shall be deducted from this account. (Paragraph C of Account 518 includes the cost of other fuels used for ancillary steam facilities.)

(b) The cost of both fossil fuel and nuclear fuel shall also reflect all refunds and credits (including any applicable interest) not in excess of $25,000 for the FERC jurisdictional allocation of any single refund/credit received from fuel suppliers/vendors applicable to previous period (non-current) payments made to such suppliers/vendors for fuel or other related allowable expenses. If such refunds/credits are not passed through and credited to applicable fuel accounts for more than one billing cycle after the Company's receipt of such refunds/credits, the Company shall include an appropriate interest credit computed in accordance with 18 C.F.R. §35.19(a).

(7) Notwithstanding the specified aforementioned treatment of fuel and purchased power costs for purposes of inclusion in determining the Company's monthly Fuel Cost Adjustment Clause (FAC) factor, the following specific credits/debits to Account 518 (nuclear fuel expenses) related to Spent Nuclear Fuel Disposal Cost refunds received from the United States Department of Energy covering the period October, 1986 through January, 1994 shall be allowed for inclusion in computing applicable monthly FAC factors:

10/86	($2,232)	07/91	($80,234)
07/88	($5,526)	08/81	($69,045)
10/88	($15,534)	09/91	($64,688)
10/89	($18,970)	10/91	($59,390)
12/90	($2,175,153)	11/91	($39,207)
01/91	($63,884)	12/91	$550,519
02/91	($59,363)	02/92	($147,600)
03/91	($63,981)	06/92	$11,136
04/91	($52,520)	07/92	($543,312)
05/91	($54,089)	01/94	$381,252
06/91	($69,544)		

(8) Additionally, credits to Accounts 501, 547, and 555 related to refunds received from El Paso Natural Gas Company as a result of FERC Docket Nos. RP90-81-000, RP91-26-000, RP91-188-000, and RP92-60-000 shall be allowed for inclusion in computing applicable monthly FAC factors. In the aggregate, such credits covering the period March 1990 through July 1994 are in the amount of ($1,168,468).

EXHIBIT IV(B)

SAMPLE
COMPUTATION OF WSPP CREDIT
FOR INCLUSION IN FERC FUEL ADJUSTMENT

MONTH OF: _____

Economy Sales/
Unit Commitment Sales/
System Capacity Sales:

Customer	(1) Total Sales Revenue ($)	(2) Fuel Cost ($)	(3) Wheeling Cost/1/ ($)	(4) Markup Col (1) - Col (2) - Col (3)
LADWP	23,150	17,703	106	5,341
NPC	4,250	3,213	65	972
SCE	217,914	161,272	1,047	55,595
SDG&E	45,788	29,351	250	16,187
SMUD	126,338	88,257	678	37,403
TOTAL SALES				115,498
				X 75%
AMOUNT TO BE CREDITED TO FUEL ADJUSTMENT				86,624

/1/ Reflects only those wheeling costs incurred by APS.

EXHIBIT IV(C)

Arizona Public Service Company
Fuel Cost Adjustment Clause "Hold" Harmless" Calculation

Table 1
Calculation of APS' "Hold Harmless" Factor

(¢/kWh)

	(1) Actual Corrected 1998 FAC Factor	(2) Actual Corrected 1999 FAC Factor	(3) Average [Col (1) + Col (2)]/2
Jan	(0.4070)	(0.2499)	(0.3285)
Feb	(0.5574)	(0.2742)	(0.4158)
Mar	(0.4778)	(0.3406)	(0.4092)
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Nov	(0.4186)	(0.1469)	(0.2828)
Dec	(0.1622)		

Table 2
Examples Showing Determination of the Applicable Monthly Corrected FAC Factor
(January 2000)
For Illustrative Purposes Only

Example A:

(¢/kWh)

(1) Preliminary FAC Factor	(2) Calculated Correction FAC Factor	(3) Actual Corrected FAC Factor Col (1) + Col (2)	(4) "Hold Harmless" Factor From Table 1	(5) Applicable FAC Factor[1]
(0.1948)	(0.2970)	(0.4918)	(0.3285)	(0.4918)

Example B:

(¢/kWh)

(1) Preliminary FAC Factor	(2) Calculated Correction FAC Factor	(3) Actual Corrected FAC Factor Col (1) + Col (2)	(4) "Hold Harmless" Factor From Table 1	(5) Applicable FAC Factor[2]
0.0246	0.1002	0.1248	(0.3285)	(0.3285)

[1] This Applicable FAC factor shall always be the lesser of the value in either Column 3 or Column 4.
[2] This Applicable FAC factor shall always be the lesser of the value in either Column 3 or Column 4.

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$$Adjustment\ Factor = \frac{F}{S} - 1.2438\ ¢/kWh$$

Where: "F" is the expense of fossil and nuclear fuel and certain purchased power costs in the current period and "S" is the kWh sales in the current period, as defined below.

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The calculation of the applicable monthly "Hold Harmless" corrected fuel adjustment factor shall be performed in accordance with Exhibit IV(C).

(2) Fuel and purchased power costs (F) shall be the cost of:

(i) Fossil and nuclear fuel consumed in the Company's own plants, and the Company's share of fossil and nuclear fuel consumed in jointly owned or leased plants; plus

(ii) the actual identifiable fossil and nuclear fuel costs associated with energy purchased for reasons other than identified in paragraph (2)(iii) below; plus

(iii) the net energy cost of energy purchases, exclusive of capacity or demand charges (irrespective of the designation assigned to such transactions) when such energy is purchased on an economic dispatch basis. Included therein may be such costs as the charges for economy energy purchases and the charges as a result of scheduled outage, all such kinds of energy being purchased by the Company to substitute for its own higher cost energy; and less

(iv) the cost of fossil and nuclear fuel recovered through all inter-system sales and specific deliveries[2/]; plus

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COMPUTATION OF WSPP CREDIT
FOR INCLUSION IN FERC FUEL ADJUSTMENT

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Unit Commitment Sales/
System Capacity Sales:

Customer	(1) Total Sales Revenue ($)	(2) Fuel Cost ($)	(3) Wheeling Cost/1/ ($)	(4) Markup Col (1) - Col (2) - Col (3)
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SCE	217,914	161,272	1,047	55,595
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TOTAL SALES				115,498
				X 75%
	AMOUNT TO BE CREDITED TO FUEL ADJUSTMENT			86,624

/1/ Reflects only those wheeling costs incurred by APS.

EXHIBIT IV(C)

Arizona Public Service Company
Fuel Cost Adjustment Clause "Hold" Harmless" Calculation

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(¢/kWh)

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June	(0.2550)	(0.1948)	(0.2249)
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Aug	0.2997	(0.4918)	(0.0961)
Sept	0.2254	(0.2361)	(0.0053)
Oct	(0.3159)	0.0378	(0.1391)
Nov	(0.4186)	(0.1469)	(0.2828)
Dec	(0.1622)		

Table 2
Examples Showing Determination of the Applicable Monthly Corrected FAC Factor
(January 2000)
For Illustrative Purposes Only

Example A:

(¢/kWh)

(1) Preliminary FAC Factor	(2) Calculated Correction FAC Factor	(3) Actual Corrected FAC Factor Col (1) + Col (2)	(4) "Hold Harmless" Factor From Table 1	(5) Applicable FAC Factor[1]
(0.1948)	(0.2970)	(0.4918)	(0.3285)	(0.4918)

Example B:

(¢/kWh)

(1) Preliminary FAC Factor	(2) Calculated Correction FAC Factor	(3) Actual Corrected FAC Factor Col (1) + Col (2)	(4) "Hold Harmless" Factor From Table 1	(5) Applicable FAC Factor[2]
0.0246	0.1002	0.1248	(0.3285)	(0.3285)

[1] This Applicable FAC factor shall always be the lesser of the value in either Column 3 or Column 4.
[2] This Applicable FAC factor shall always be the lesser of the value in either Column 3 or Column 4.

Exhibit F

Notice of Filing

UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

Pinnacle West Capital Corporation	)	**Docket No. ER00-____-000**
	)	
Arizona Public Service Company	)	**Docket No. ER99-4124-000**
	)	
APS Energy Services Company, Inc.	)	**Docket No. ER99-4122-000**

NOTICE OF FILING
(____, 2000)

Take notice that on April ___, 2000, Pinnacle West Capital Corporation ("PWCC"), filed an application for an order authorizing it to make wholesale sales of electric power at market-based rates, waiving certain of the Commission's regulations and seeking blanket approval to engage in certain transactions. PWCC, Arizona Public Service Company and APS Energy Services Company, Inc. (collectively, the "Pinnacle West Companies"), also seek permission to transact among themselves at market-based rates and for modification of their wholesale code of conduct requirements and certain wholesale contracts.

Any person desiring to be heard or to protest said filing should file a motion to intervene or protest with the Federal Energy Regulatory Commission, 888 First Street, N.E., Washington, D.C. 20426, in accordance with Rules 211 and 214 of the Commission's Rules of Practice and Procedures (18 C.F.R. § 385.211 and 18 C.F.R. § 385.214). All such motions or protests should be filed on or before _____, 2000. Protests will be considered by the Commission in determining the appropriate action to be taken, but will not serve to make protestants parties to the proceedings. Any person wishing to become a party must file a motion to intervene. Copies of this filing are on file with the Commission and are available for public inspection. This filing may also be viewed on the Internet at http://www.ferc.fed.us/online/rims.htm (call 202-208-2222 for assistance).

David P. Boergers
Secretary

CERTIFICATE OF SERVICE

I hereby certify that I have this day served the foregoing document upon each person designated on the official service list compiled by the Secretary in this proceeding.

Dated at Washington, D.C., this 21st day of April, 2000.

Alex M. Schnell

Alex M. Schnell
Morgan, Lewis & Bockius LLP
1800 M Street, N.W.
Washington, D.C. 20036
(202) 467-7622

Attorney for
Pinnacle West Capital Corporation

ORIGINAL

1800 M Street, N.W.
Washington, D.C. 20036-5869
202-467-7000
Fax: 202-467-7176

Morgan, Lewis & Bockius LLP
COUNSELORS AT LAW

FILED
OFFICE OF THE SECRETARY
00 JUL 28 PM 4:35
FEDERAL ENERGY
REGULATORY COMMISSION

July 28, 2000

ER00-3312-000

Honorable David P. Boergers, Secretary
Federal Energy Regulatory Commission
888 First Street, N.E.
Washington, D.C. 20426

Re: Application of Pinnacle West Energy Corporation for Order Approving Market-Based Rates, Docket No. ER00- -000

Dear Secretary Boergers:

Pursuant to Section 205 of the Federal Power Act, 16 U.S.C. § 824d (1994), and Rule 205 of the Rules of Practice and Procedure of the Federal Energy Regulatory Commission, 18 C.F.R. § 385.205 (1999), Pinnacle West Energy Corporation ("PWE") hereby submits for filing six copies of an Application for Order Approving Market-Based Rates.

A form of notice suitable for publication in the *Federal Register* and a copy of the notice on a computer diskette are attached hereto.

If you have any questions about this filing, please feel free to contact me.

Respectfully submitted,

John D. McGrane
Morgan, Lewis & Bockius LLP
1800 M Street, N.W.
Washington, D.C. 20036-5869
Phone: (202) 467-7000

Barbara M. Champion, Senior Attorney
Pinnacle West Capital Corporation
P.O. Box 53999

DKT/OSEC
000808-0863-1

DOCKETED
JUL 28 2000

Morgan, Lewis
& Bockius LLP

Mail Station 8695
Phoenix, Arizona 85072-3999
Phone: (602) 250-3547

Attorneys for
Pinnacle West Energy Corporation

Enclosures

ORIGINAL

OFFICE OF THE SECRETARY
00 JUL 28 PM 4:48
FEDERAL ENERGY REGULATORY COMMISSION

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Pinnacle West Energy Corporation) **Docket No. ER00-____-000**

ER00-3312-000

APPLICATION OF PINNACLE WEST ENERGY CORPORATION FOR ORDER APPROVING MARKET-BASED RATES

Pursuant to Section 205 of the Federal Power Act, 16 U.S.C. § 824d, and Rule 205 of the Rules of Practice and Procedure of the Federal Energy Regulatory Commission ("FERC" or the "Commission"), 18 C.F.R. § 385.205 (1998), Pinnacle West Energy Corporation ("PWE") hereby submits for filing this Application for authorization to engage in wholesale power sales at market-determined prices. PWE requests that the Commission take the following actions: (1) accept its Market-Based Rate Tariff (the "Market Rate Tariff") for wholesale sales of energy and capacity, including ancillary services within the California Independent System Operator ("ISO"); (2) approve the code of conduct governing PWE's relationship with its parent company, Pinnacle West Capital Corporation ("PWCC"), its public utility affiliate, Arizona Public Service Company ("APS"), and its marketing affiliate, APS Energy Services Company, Inc. ("APSES") (collectively, the "Pinnacle West Companies"); and (3) grant waivers of certain of the Commission's regulations and blanket authorizations of other actions under the Commission's regulations. Pursuant to Section 35.3(a) of the Commission's regulations, PWE also requests an effective date of 60 days after this filing, or the date on which the Commission issues an order approving PWE's application for market-based rates, whichever is earlier.

I. DESCRIPTION OF PWE

PWE was incorporated in Arizona on September 27, 1999, whose principal place of business is located at 400 North Fifth Street, Phoenix, Arizona, 85004. PWE does not own distribution facilities or transmission facilities other than those facilities associated with and supporting generation facilities that PWE will own (e.g., step-up transformers and related equipment). PWE is a subsidiary of PWCC, a holding company that is exempt from registration under the Public Utility Holding Company Act of 1935, in accordance with Securities and Exchange Commission ("SEC") Rule 2(a)(1).[1] PWCC also owns APS, a public service corporation organized under the laws of the State of Arizona, which is engaged in the business of transmitting and distributing electricity in all or part of eleven of Arizona's fifteen counties. APS is also authorized to sell wholesale power and energy at market-based rates.[2] In its order granting market-based rate authority to APS, the Commission found that APS does not possess market power.[3]

Additionally, PWCC is the parent of APSES, a marketer of electricity and energy-related services primarily to retail customers in Arizona and California. APSES also engages in wholesale marketing and brokering of electricity that is largely incidental to its retail function. In a Letter Order dated October 13, 1999,[4] the Acting Secretary of the Commission, pursuant to delegated authority, accepted APSES' market-based rate schedule for filing.

On April 21, 2000, PWCC filed an application for authorization to engage in wholesale power sales at market based rates and requested that the Commission permit

---

1 17 C.F.R. § 250.2 (1999); *see* SEC File No. 69-306.

2 *Arizona Public Service Co.*, 79 FERC ¶ 61,022 (1997). APS recently filed an updated market analysis in connection with its market-based rates. *Arizona Public Service Company*, Docket No. ER00-1875-000 (March 14, 2000).

3 79 FERC at 61,098-99.

4 Reported at 89 FERC ¶ 61,024.

PWCC and its affiliates, APS and APSES, to engage in inter-affiliate transactions at market based rates in conjunction with changes to their respective codes of conduct.[5]

On June 20, 2000, the Commission conditionally accepted for filing a proposed market-based rate tariff and code of conduct for PWCC in Docket No. ER00-2268-000. In doing so, the Commission implicitly reaffirmed its earlier determination that PWCC's subsidiaries, APS and APSES, do not possess market power in the relevant generation or transmission markets. As ordered by the Commission, PWCC submitted a compliance filing to resolve all remaining concerns of the Commission regarding potential affiliate abuse and the effect of affiliate transactions on captive wholesale customers with fuel adjustment clauses. Upon acceptance of its compliance filing, PWCC will be authorized to engage in inter-affiliate transactions.

PWE and APSES were formed in response to the restructuring currently underway in the wholesale and retail sectors of the electric industry in Arizona and elsewhere. PWE is currently in the business of owning and operating generating facilities and is actively engaged in developing and/or acquiring new generation facilities in Arizona and elsewhere. In Arizona, the Arizona Corporation Commission ("ACC") has implemented a plan to permit retail access. On October 6, 1999, the ACC approved a Settlement Agreement between APS and several customer groups and consumer advocates resolving retail electric competition-related issues and approving unbundled tariffs.[6]

Under the terms of the Electric Competition Rules of the ACC and APS's Settlement Agreement, retail choice for APS's retail customers is being phased-in. All of APS's retail customers will be entitled to choose their retail power supplier beginning

5 *Pinnacle West Capital Corporation, et al.*, Docket No.ER00-2268-000.

6 ACC Decision No. 61973.

January 1, 2001.[7] APS's retail customers that are not yet entitled to chose their retail power supplier are subject to retail rate reductions that will continue until after customer choice becomes available.[8] Under the Settlement Agreement, APS is entitled to apply for a change in the agreed upon rate reductions only in the event of an emergency or a material change in its cost of service as a result of specified extraordinary events.

Pursuant to the ACC approved Settlement Agreement, APS is required to divest generation assets by December 31, 2002.[9] On July 28, 2000, APS filed pursuant to Section 203 of the Federal Power Act, 16 U.S.C. § 824(b), and Part 33 of the Regulations of the Commission, 18 C.F.R., Part 33, a request to transfer to PWE certain FERC-jurisdictional facilities associated with generation assets being transferred to PWE as a further step toward a corporate restructuring. Once completed, APS will become primarily a "wires" company.

Each sector of the electric utility market is becoming increasingly competitive and present greater market opportunities than have previously existed. Transferring the generation assets to PWE will help PWCC and its affiliates adapt their electric businesses to these changing markets. The restructuring plan will allow PWCC and its affiliates to better compete in these markets and permit it to better serve its customers and its shareholders.

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7 *See* ACC approved Settlement Agreement, § 1.1.

8 *See* ACC approved Settlement Agreement, §§ 2.2, 2.6, 2.7.

9 *See* ACC approved Settlement Agreement, § 4.1.

II. COMMUNICATIONS

PWE respectfully requests that service of pleadings and deliveries of communications and correspondence concerning this matter be directed to the following:

Barbara M. Gomez
Treasurer
Pinnacle West Energy Corporation
400 North 5th Street
Mail Station 9996
Phoenix, Arizona 85004
Phone: (602) 250-5677

Barbara M. Champion
Senior Attorney
Pinnacle West Capital Corporation
400 North 5th Street
Mail Station 8695
Phoenix, Arizona 85004
Phone: (602) 250-3547

Joel R. Spitzkoff
Manager of Federal Regulation
Arizona Public Service Company
400 North 5th Street
Mail Station 9905
Phoenix, Arizona 85004
Phone: (602) 250-2949

John D. McGrane
Mary Ann K. Huntington
Kristina E. Beard
Morgan, Lewis & Bockius LLP
1800 M Street, N.W
Washington, D.C. 20036
Phone: (202) 467-7621

Applicants request that the above-listed individuals be placed on the official service list compiled for this proceeding.

III. LIST OF MATERIALS SUBMITTED WITH THIS FILING

This filing contains the following materials:

1. Exhibit A - PWE Market-Rate Tariff, including a form of service agreement;

2. Exhibit B - PWE Code of Conduct governing its relationship with PWCC and its affiliates;

3. Exhibit C - Notice of Filing suitable for publication in the Federal Register, with an electronic version on diskette.

IV. REQUEST FOR MARKET-BASED RATE APPROVAL FOR PWE

The Commission traditionally has permitted an entity -- whether a public utility, an independent power producer, or a power marketer -- to engage in wholesale sales of power and energy at market-based rates if the entity can demonstrate that neither it nor

any of its affiliates have market power in relevant markets for generation service and transmission service (or have adequately mitigated such market power) and that neither can erect barriers to entry.[10] In evaluating requests for market-based rates, the Commission also considers whether there is any evidence of, or potential for, affiliate abuse or reciprocal dealing between the applicant and its affiliates.[11] As demonstrated in this application and its supporting materials, PWE satisfies the Commission's criteria and should be granted authority to engage in wholesale power sales transactions at market-based rates, including sales of ancillary services into the California ISO.[12] In addition to governing the market-based sales of power and energy, the Market Rate Tariff will permit PWE to reassign transmission capacity, transmission rights, and associated ancillary services acquired for its own use under open access transmission tariffs. The Market Rate Tariff permits PWE to resell such capacity and rights at a price not higher than the highest of (1) the price PWE originally paid for the service, (2) the transmission provider's maximum rate for the service on file at the time of the resale, or (3) PWE's own opportunity costs capped at the applicable transmission provider's cost of expansion at the time of the sale to the eligible customer.[13] The resold service will be provided in accordance with the terms and conditions of service of the original transmission provider's applicable open access transmission tariff. PWE's proposed reassignment of transmission and associated ancillary services is wholly consistent with reassignment

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10 *See, e.g., Heartland Energy Service, Inc.*, 68 FERC ¶ 61,223, at 62,060 (1994) ("*Heartland*").

11 *Id.*

12 The ancillary services PWE seeks authority to sell into the California ISO are: replacement reserve service, regulation and frequency response service, energy imbalance service, operating reserve-spinning reserve service and operating reserve-supplemental reserve service.

13 PWE will not charge a rate based on its opportunity costs absent a separate filing under Section 205 of the Federal Power Act.

provisions the Commission previously has accepted.[14]

A. Market Power

With respect to its market power concerns, the Commission generally requires that an entity seeking authorization to transact at market-based rates (1) demonstrate that the entire output of its or any of its affiliates' generating facilities is committed under long-term contracts, (2) demonstrate that the applicant or its affiliates already are authorized to sell power at market-based rates, or (3) submit a market analysis that indicates that neither the applicant nor its affiliates have generation dominance in the relevant markets.[15]

PWE's parent company PWCC and its affiliates APS and APSES are already authorized to sell power at market-based rates.[16] PWE relies on the market power study that its affiliates relied upon in support of their market-based rate applications, consistent with FERC precedent.[17] The transfer of generating assets between APS and PWE does not alter the results of the market power study. As such, the Commission should reach the same conclusion here that it reached in *Arizona Public Service Co.* -- that PWE does

14 *See, e.g., Alliant Services Company*, 85 FERC ¶ 61,344 (1998); *Select Energy, Inc.*, 85 FERC ¶ 61,290 (1998); *Commonwealth Edison Co.*, 78 FERC ¶ 61,312 (1997).

15 *LG&E Power Marketing, Inc.*, 68 FERC ¶ 61,247, at 62,121 (1994).

16 *See Pinnacle West Capital Corp., et al.*, 91 FERC ¶ 61,290 (2000); *Arizona Public Service Co.*, 79 FERC at 61,098-101; *APS Energy Services*, Letter Order, 89 FERC ¶ 61,024.

17 *See, e.g., Alliant Services Co.*, 85 FERC ¶ 61,344 (finding no market power based on affiliates' market study approved in earlier merger order); *Louisville Gas and Electric Co., et al.*, 85 FERC ¶ 61,215 (1998) (finding no market power based on affiliates' market studies approved in earlier market-based rate application orders).

not have generation market power.[18]

B. Transmission Market Power

In order to ensure that applicants for market-based rate authority do not possess transmission market power, the Commission generally requires the applicant, or its affiliated public utility, to file or have on file open access transmission tariffs for the provision of comparable services.[19] APS filed its open access tariff on July 9, 1996 (Docket No. OA96-153-000), and a revised open access tariff on July 12, 1996 (Docket No. ER96-2401-000). The Commission consolidated the two dockets and, on June 18, 1999, issued a letter order accepting a settlement governing APS's transmission rates in the consolidated dockets.

PWE will not own any transmission facilities except for those transmission facilities associated with the power plants being transferred (i.e. step-up transformers and related equipment). Accordingly, the availability of open access transmission service over APS' transmission facilities under the APS transmission tariff eliminates the potential for any exercise of transmission market power by PWE.

C. Barriers to Entry

In previous cases, the Commission has examined the possibility that an entity might be able to erect other barriers to entry as a possible ground for denying the

18 As explained in footnote 2, above, APS recently filed an update to its market power study. *See Arizona Public Service Co.*, Docket No. ER00-1875-000. That update was accepted by the Commission on May 2, 2000.

19 *See, e.g., Southern Indiana Gas & Electric Company*, 77 FERC ¶ 61,021 (1996).

authority to charge market-based rates.[20] PWE, PWCC, APS and APSES are not affiliated with entities that could impose barriers to entry in the electric power generation business through their ownership or control of any resources or inputs that could be essential to market entry by competitors.

D. Affiliate Abuse and Reciprocal Dealing

In evaluating market-based rate applications of affiliated power marketers, the Commission considers the potential for affiliate abuse and reciprocal dealing. The Commission has explained that affiliate abuse takes place when a public utility and an affiliated power marketer transact in ways that result in a transfer of benefits from the public utility (and the ratepayers) to the power marketer (and the shareholders).[21] Here, due to the restructuring of the Arizona retail market and the commitments made with respect to APS's wholesale customers in *Pinnacle West Capital Corporation, et al*, Docket No. ER00-2268-001 there is no potential for affiliate abuse. Accordingly, the Commission should permit PWE and the other Pinnacle West Companies to engage in transactions at negotiated market-based prices with each other under the codes of conduct governing relations between the Pinnacle West Companies.

The proposed PWE code of conduct that is similar to the codes of conduct for PWCC, APS, and APSES is attached as part of Exhibit A. The Pinnacle West Companies note that the ACC code of conduct will also continue to govern relationships between APS and APSES.

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20 *Heartland*, 68 FERC at 62,062.

21 *Id.*; *Wholesale Power Services, Inc.*, 72 FERC ¶ 61,284 (1995).

As detailed in *Pinnacle West Capital Corporation, et al.*, Docket No. ER00-2268-001, there is no risk of harm to the retail or wholesale customers of PWE's affiliate, APS, from the proposed changes to the codes of conduct. APS's wholesale customers are protected by putting in place measures that will prevent any potentially inappropriate costs associated with affiliated transactions from being passed through to these customers. Under the Arizona restructuring and the Settlement Agreement, APS's retail customers are protected by what is in essence a rate reduction and freeze and/or their ability to choose their electric supplier.[22]

E. The Commission's Filing Requirements

Consistent with the Commission's requirements, PWE commits that it will file quarterly transaction summaries and satisfy the Commission's other standard reporting requirements for affiliated power marketers.[23] Specifically, PWCC will file umbrella service agreements for short-term transactions (one year or less) within 30 days of the date of commencement of service, to be followed by quarterly transaction summaries for specific sales. For long-term transactions (longer than one year), the actual service agreement for each transaction will be filed within 30 days after commencement of

22 *See AmerGen Energy Co., L.L.C.*, 90 FERC ¶ 61,080 (2000) (ratepayers who have retail choice or are protected by a rate freeze are not captive customers); *Green Power Partners I, LLC, et al.*, 88 FERC ¶ 61,005 (1999) (waiving code of conduct requirement for UGI Development Co. because UGI does not have captive customers); *Enron Energy Services Power, Inc.*, 81 FERC ¶ 61,267 (1997) ("we will not accept PECO's request that we treat customers participating in a state retail [choice] program as captive customers requiring expansion of Enron Energy's code of conduct").

23 *See Southern Co. Services, Inc.*, 87 FERC ¶ 61,214 (1999); *Horizon Energy Co.*, 81 FERC ¶ 61,368 (1997).

service.[24]

PWE commits that it will file a revised market power analysis every three years.[25]

V. REQUEST FOR EFFECTIVE DATE AND WAIVERS

Consistent with the Commission's decisions in previous power marketer cases, PWE respectfully requests that the Commission waive the following requirements of the Commission's regulations: (1) the accounting and reporting requirements under Parts 41, 101, and 141 of the Commission's regulations; (2) the interlocking directorate filing requirements under Part 45 of the Commission's regulations, or, alternatively, permission to file abbreviated filings with respect to interlocking directorates under Part 45; (3) the filing requirements of Subparts B and C of Part 35 of the Commission's regulations, other than Sections 35.12(a), 35.13(b), 35.15 and 35.16; and (4) blanket authorization under Part 34 of all future issuances of securities and assumptions of obligations or liabilities as guarantor, endorser, surety or otherwise in respect of any security of any person.[26] Pursuant to Section 35.3(a) of the Commission's regulations, PWE respectfully requests that the Commission accept the Market Rate Tariff for filing and permit it to become effective the earlier of either sixty days after the date of this filing or the date upon which the Commission grants acceptance.

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24 *Southern Co. Services, Inc.*, 87 FERC at 61,848-49.

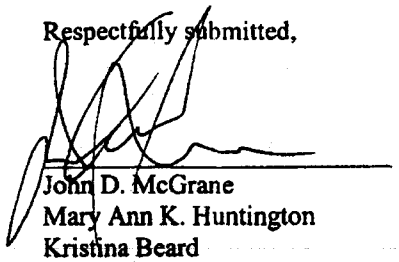
25 *See Morgan Stanley Capital Group, Inc.*, 69 FERC ¶ 61,175 (1994) (as clarified in *Engelhard Power Marketing, Inc.*, 70 FERC ¶ 61,250 (1995)).

26 *See, e.g., AES Huntington Beach, L.L.C.*, 83 FERC ¶ 61,100 (1998).

VI. CONCLUSION

PWE requests that the Commission issue an order granting: (1) authorization for PWE to engage in wholesale sales of electric power at market-based rates, including market-rate sales to its affiliates and sales of ancillary services at market-based rates in the California market; (2) acceptance of PWE's request for permission to reassign transmission capacity; (3) acceptance of the PWE Market Rate Tariff for filing effective the earlier of sixty days after the filing of this application or upon issuance of an order accepting the Tariff for filing; (4) approval of the proposed code of conduct governing PWE's relationship with the other Pinnacle West Companies; (5) certain blanket authorizations; and (6) certain waivers of the Commission's regulations as requested herein.

Respectfully submitted,



John D. McGrane
Mary Ann K. Huntington
Kristina Beard
Morgan, Lewis & Bockius LLP
1800 M Street, N.W.
Washington, D.C. 20036
Phone: (202) 467-7000

Barbara M. Champion, Senior Attorney
Pinnacle West Capital Corporation
P.O. Box 53999
Mail Station 8695
Phoenix, Arizona 85072-3999
Phone: (602) 250-3547

Attorneys for
Pinnacle West Energy Corporation

Dated: July 28, 2000

Exhibit A

Pinnacle West Energy Corporation

Market-Based Rate Tariff

Pinnacle West Energy Corporation

MARKET-BASED RATE TARIFF

1. Availability: Pinnacle West Energy Corporation ("PWE") makes electric capacity or energy available for sale for resale under this Rate Schedule to any purchaser.

2. Applicability: This schedule is applicable to all sales of electric capacity and/or energy by PWE

   This schedule is also available for purchases by the California Independent System Operator Corporation and its suppliers and market participants of Replacement Reserve Service and the following ancillary services as defined by the Commission: Regulation and Frequency Response Service, Energy Imbalance Service, Operating Reserve-Spinning Reserve Service, and Operating Reserve-Supplemental Reserve Service.

   This schedule also is applicable to the reassignment of transmission capacity, transmission rights and associated ancillary services, that PWE has acquired for its own use on the transmission systems of transmission providers.

3. Rates: All sales of electric capacity or energy shall be made at rates established by agreement between the purchaser and PWE.

4. Other Terms and Conditions: All other terms and conditions shall be established by agreement between the purchaser and PWE.

5. Effective Date: This Rate Schedule shall be effective on the date established by FERC.

6. Reassignment of Transmission Rights: PWE may reassign transmission capacity, transmission rights, and associated ancillary services that it has reserved for its own use at a price not to exceed the highest of: (1) the original transmission rate paid by PWE; (2) the applicable transmission provider's maximum stated firm transmission rate on file at the time of the transmission reassignment; or (3) PWE's own opportunity costs, capped at the applicable transmission provider's cost of expansion at the time of the sale to the eligible customer. PWE will not recover opportunity costs in connection with reassignment without making a separate filing under Section 205. Except for the price, the terms and conditions under which the reassignment is made shall be under the terms and conditions governing the original grant by the transmission provider. Transmission and associated ancillary services may only be reassigned to a customer eligible to take service under the transmission provider's open access transmission tariff or other transmission rate schedules. PWE will report the name of the assignee in its quarterly reports.

Issued by: Alan Propper
Director, Pricing and Regulation
Issued on: July 28, 2000

Effective:_____

Pinnacle West Energy Corporation

MARKET-BASED RATE TARIFF

SERVICE AGREEMENT

This Service Agreement, dated as of _____, is entered into by and between Pinnacle West Energy Corporation ("PWE") and _____ ("Customer"), pursuant to PWE's Market-Based Rate Tariff, FERC Electric Tariff No. 1 ("Tariff").

Each transaction hereunder will be carried out under terms and conditions as agreed upon by PWE and the Customer in accordance with the terms and conditions of the Tariff.

IN WITNESS WHEREOF, PWE and Customer have caused this Service Agreement to be executed by their respective authorized officials as of the date first above written.

Customer	**Pinnacle West Energy Corporation**
_____	
Customer	
_____	_____
Signature of Representative Date	Signature of Representative Date
_____	_____
Name of Representative	Name of Representative
_____	_____
Title of Representative	Title of Representative

Issued by: Alan Propper
Director, Pricing and Regulation
Issued on: July 28, 2000

Effective:_____

Exhibit B

Pinnacle West Energy Corporation

Code of Conduct

Pinnacle West Energy Corporation

STATEMENT OF POLICY AND CODE OF CONDUCT WITH RESPECT TO THE RELATIONSHIP BETWEEN PINNACLE WEST ENERGY CORPORATION AND ARIZONA PUBLIC SERVICE COMPANY

The following Code of Conduct will govern the relationship between Pinnacle West Energy Corporation ("PWE") and any other marketing affiliates that may be authorized by the Federal Energy Regulatory Commission to engage in sales for resale of energy and capacity at market-based rates (the "Marketing Affiliates"), and Arizona Public Service Company ("APS").

Marketing of Power

1. To the maximum extent practical, the employees of the Marketing Affiliates will operate separately from the employees of APS.

2. Sales of any non-power goods or services by APS, including sales made through affiliated EWGs or QFs, to the Marketing Affiliates will be at the higher of cost or market price.

3. Sales of any non-power goods or services by the Marketing Affiliates to APS will not be at a price above market.

Exhibit C

NOTICE OF FILING

92 FERC ¶ 61,248

UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

Before Commissioners: James J. Hoecker, Chairman;
William L. Massey, Linda Breathitt,
and Curt Hébert, Jr.

Pinnacle West Energy Corporation Docket No. ER00-3312-000

ORDER ACCEPTING FOR FILING PROPOSED MARKET-BASED RATE TARIFF

(Issued September 26, 2000)

In this order, the Commission accepts for filing a proposed market-based rate tariff filed by Pinnacle West Energy Corporation (PWE).

BACKGROUND

On July 28, 2000, PWE filed an application, under section 205 of the Federal Power Act (FPA),[1] seeking: (1) authority for PWE to engage in wholesale sales of electric power at market-based rates, including market-based rate sales to its affiliates, and sales of ancillary services within the California Independent System Operator (California ISO) market; (2) authority for PWE to reassign transmission capacity and transmission rights; (3) approval of a code of conduct for PWE;[2] and (4) waivers of certain of the Commission's regulations and blanket authorizations for other actions under the Commission's regulations.

PWE's application states that PWE's parent company, Pinnacle West Capital Corporation (PWCC), and its affiliates, Arizona Public Service Company (APS) and APS

[1] 16 U.S.C. § 824d (1994).

[2] PWE proposes to exclude from its code of conduct provisions that require simultaneous disclosure to the public of all market information shared between APS and its affiliates.

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Energy Services Company (APSES) (collectively, Pinnacle West Companies), are already authorized to sell power at market-based rates.[3]

PWE's application also states that the Arizona Corporation Commission (Arizona Commission) is in the process of modifying its rules on retail electric competition within Arizona to allow full retail choice.[4] On October 6, 1999, the Arizona Commission approved a settlement agreement between APS and several customer groups and consumer advocates resolving retail electric competition-related issues and approving unbundled tariffs.[5] Pursuant to the settlement approved by the Arizona Commission, APS is required to divest its generation assets by December 31, 2002.[6]

Notice of the filing was published in the Federal Register, with comments, protests, and interventions due on or before August 18, 2000.[7]

On July 28, 2000, the same date that PWE filed the instant application, APS filed a request pursuant to section 203 of the FPA,[8] and Part 33 of the Commission's Regulations, 18 C.F.R. § 33.1, et seq., to transfer to PWE certain Commission jurisdictional facilities associated with generation assets being transferred to PWE as a further step toward a corporate restructuring.[9]

Interventions and Protests

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[3]PWE Application at 2. See Pinnacle West Capital Corporation, 91 FERC ¶ 61,290 (2000) (PWCC), reh'g pending; Arizona Public Service Company, 79 FERC ¶ 61,022 (1997); APS Energy Services Company, Inc., Letter Order, 89 FERC ¶ 61,024 (1999).

[4]PWE Application at 3.

[5]Id.

[6]Id. at 4.

[7]65 Fed. Reg. 48,985 (2000).

[8]16 U.S.C. § 824(b) (1994).

[9]APS's application under § 203 of the FPA is currently pending Commission review in Docket No. EC00-118-000.

The Arizona Commission filed a notice of intervention. A timely motion to intervene was filed by Salt River Agricultural Improvement and Power District (Salt River). Timely motions to intervene and protests were filed by Tucson Electric Power Company (Tucson), Citizens Utilities Company (Citizens), and jointly by a number of electrical and irrigation districts in the State of Arizona (Arizona Districts).[10] A late-filed motion to intervene and protest was filed by Tohono O'odham Utility Authority (TOUA).

Tucson and Arizona Districts reiterate concerns they raised in Docket No. ER00-2268-000, in which PWCC sought and was granted market-based rate authority, including authority to make market-based sales to affiliates.[11] Tucson argues that PWE's application raises issues about market power and affiliate abuse. Arizona Districts raise similar concerns and also argue that PWE's filing should be rejected because it fails to meet the Commission's filing requirements under section 205 of the FPA for sales to affiliates at market-based rates. Citizens protests PWE's request to sell power to its affiliated franchised utility, APS, as well as other affiliated marketers, at market-based rates, when considered in the context of APS divesting all its generating facilities to PWE (currently pending in Docket No. EC00-118-000). TOUA argues that, taken together, the instant filing and the filing in Docket No. EC00-118-000 will have an adverse impact on its rates, especially on the system incremental cost (SIC) feature under its wholesale power sales contracts with APS. TOUA also requests consolidation of this proceeding with the proceeding in Docket No. EC00-118-000.

On August 31, 2000, PWE filed for leave to file an answer and an answer to Arizona Districts' protest. On September 5, 2000, PWE filed for leave to file an answer and an answer to TOUA's protest.

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[10]Arizona Districts are comprised of: Aguila Irrigation District; Buckeye Water Conservation & Drainage District; Electrical District No. 1 of Pinal County; Electrical District No. 3 of Pinal County; Electrical District No. 6 of Pinal County; Electrical District No. 7 of Maricopa County; Electrical District No. 8 of Maricopa County; Harquahala Valley Power District; Maricopa County Municipal Water Conservation District No. 1; McMullen Valley Water Conservation & Drainage District; Roosevelt Irrigation District; and Tonopah Irrigation District.

[11]See PWCC, 91 FERC at 61,998-99; Tucson Protest at 4; Arizona Districts Protest at 4.

DISCUSSION

As a preliminary matter, Arizona Commission's notice of intervention and the timely, unopposed motions to intervene of Salt River, Tucson, Citizens, and Arizona Districts serve to make them parties to this proceeding.[12] In addition, we will grant TOUA's untimely motion to intervene, given TOUA's interest in this proceeding, the early stage of this proceeding, and the absence of any undue prejudice or delay.

While Rule 213(a)(2) of the Commission's Rules of Practice and Procedure, 18 C.F.R. § 385.213(a)(2) (2000), generally prohibits the filing of an answer to a protest, we will accept PWE's answers because they aid our understanding and resolution of the issues in this proceeding.

A. Market-Based Rates

The Commission allows power sales at market-based rates if the seller and its affiliates do not have, or have adequately mitigated, market power in generation and transmission and cannot erect other barriers to entry. For an affiliate of a transmission-owning public utility to demonstrate the absence or mitigation of market power, the public utility must have on file with the Commission an open access transmission tariff for the provision of comparable services. The Commission also considers whether there is evidence of affiliate abuse or reciprocal dealing.[13]

As we explain below, we find that PWE's proposed market-based rate tariff meets these standards. Accordingly, we will accept the proposed tariff for filing, without suspension or hearing, to become effective on September 25, 2000, 60 days after the date of filing.

1. Generation Market Power

As a result of the Arizona retail choice program, APS has proposed to divest its generation assets and for PWE to acquire from it certain FERC-jurisdictional generation facilities. APS's application for Commission approval of this transfer of jurisdictional

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[12]See 18 C.F.R. § 385.214 (2000).

[13]E.g., Progress Power Marketing, Inc., 76 FERC ¶ 61,155 at 61,919 (1996), letter order approving settlement, 79 FERC ¶ 61,149 (1997); Northwest Power Marketing Company, L.L.C., 75 FERC ¶ 61,281 at 61,889 (1996); accord Heartland Energy Services, Inc., et al., 68 FERC ¶ 61,223 at 62,060-063 (1994) (Heartland).

facilities is pending before the Commission in Docket No. EC00-118-000. However, for purposes of evaluating the instant application, we will assume that this transfer of facilities takes place.

The Commission recently evaluated the generation dominance of PWE's affiliates in Docket No. ER00-1875-000, and, in our view, the proposed transfer of generating assets between APS and PWE would not alter the results of that market power study.[14] In addition, we are not aware of any other material changes in circumstances that would require a new market analysis. Thus, we find that PWE meets the Commission's generation market power standard for approval of market-based rates.

2. Transmission Market Power

When an affiliate of a transmission-owning public utility seeks authorization to charge market-based rates, the Commission has required the public utility to have an open access transmission tariff on file before granting such authorization. PWE does not own any transmission facilities. Its affiliate, APS, filed an open access transmission tariff with the Commission in Docket No. OA96-153-000, as amended in Docket No. ER96-2401-000. Both filings were accepted by the Commission in a letter order dated June 18, 1999. Thus, we find that PWE meets the Commission's transmission market power standard for approval of market-based rates.

3. Other Barriers to Entry

Based on our review of the application, we are satisfied that there are no issues regarding other barriers to entry of concern here.

4. Affiliate Abuse/ Reciprocal Dealing

PWE proposes to engage in transactions with its affiliated Pinnacle West Companies at market-based rates. PWE argues, based on the restructuring of the Arizona retail market (including a retail rate reduction, retail rate freeze, and the implementation of retail choice) and the commitments made to APS's wholesale customers in PWCC and

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[14]On March 14, 2000, APS submitted an updated generation market study in Docket No. ER00-1875-000. This market study was accepted for filing by the Director, Division of Corporate Applications, Office of Markets, Tariffs, and Rates, acting under delegated authority, in an unpublished letter order issued on May 2, 2000.

Pinnacle West Capital Corporation, Docket No. ER00-2268-001,[15] that its application does not raise affiliate abuse issues.[16] Thus, PWE argues, there is no need for its code of conduct to include provisions requiring the simultaneous public disclosure of all market information shared among the affiliates.

Citizens argues that it may face higher rates for capacity and energy through the SIC component of its requirements contract with APS (Citizens' PSA) if PWE obtains market-based rates. Citizens expresses concern that APS's divestiture of its generating assets to PWE, along with PWE's ability to sell power to APS at negotiated rates, will allow APS to manipulate the calculation of the SIC.

Citizens also argues that the Palo Verde Index is not an effective safeguard to protect wholesale customers from affiliate abuse. Citizens states that the Palo Verde Index figure significantly exceeds Citizens' current SIC energy rates and is so inflated that, in most cases, the SIC methodology will determine the applicable energy charge, even if it includes above-market purchased power costs resulting from affiliate transactions. Thus, Citizens argues that use of the Palo Verde Index will allow PWE substantial latitude to inflate APS's SIC customers' rates. Citizens also argues that PWE's proposed use of the Palo Verde Index neither replicates nor reflects the parties' economic bargain set out in Citizens' PSA and thus is not a reasonable proxy for APS's SIC.

TOUA raises concerns similar to those raised by Citizens. It states that the combined effect of PWE's request for market-based rates and APS's request for approval of its sale of generation facilities to PWE will be to increase TOUA's rates, especially the SIC component of the rates. TOUA expresses concern that APS's SIC costs may be

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[15]PWCC's market-based rate compliance filing was accepted for filing by the Director, Division of Corporate Applications, Office of Markets, Tariffs, and Rates, acting under delegated authority, in an unpublished letter order issued on August 25, 2000 in Docket No. ER00-2268-001. This filing included fuel adjustment clause revisions consistent with our order in PWCC. See PWCC, 91 FERC at 61,998-99.

[16]PWE proposes to mitigate any potential harm to APS's wholesale customers by putting in place measures that will protect the customers from the improper pass-through of costs associated with affiliate transactions. In the case of APS's wholesale customers whose contracts include a pricing provision based on APS's system incremental cost (SIC), PWE proposes to cap the pass-through of costs to such wholesale customers at the lesser of APS's SIC or prices calculated based on the Palo Verde Index. In the case of APS's wholesale customers with an FAC, PWE commits to abide by the commitments reflected in its compliance filing in Docket No. ER00-2268-001.

driven up by inter-affiliate power purchases at negotiated rates. TOUA argues that this could result in PWE raising its customers' costs merely by making sales to its affiliates at inflated prices.

In its protest, Tucson incorporates by reference arguments that it made in PWCC (rehearing pending).

Arizona Districts urges the Commission to deny PWE's application to engage in wholesale power sales at market-based rates, including ancillary services and inter-affiliate transactions at market-based rates, for the same reasons it offered in its intervention in PWCC.

Commission Conclusion

As the Commission has explained in previous cases, there is a concern whenever a traditional public utility can transact with an affiliated power marketer in such a way as to transfer benefits from a power sale from the public utility's captive ratepayers to the shareholders.[17] PWE argues that there is no potential for affiliate abuse here because APS's retail customers are protected by a rate reduction and freeze and/or their ability to choose their electric suppliers. As to APS's captive wholesale customers, PWE proposes to protect these customers against potential cost shifting by offering to abide by the same commitments made by APS, and accepted by the Commission, with respect to APS's wholesale customers in PWCC.

In response to concerns raised by two of APS's customers, Citizens and TOUA, PWE represents that the transfer of contracts and generation assets from APS to PWCC and PWE will not affect the rate protections provided in Docket No. ER00-2268-000 to APS's wholesale customers. PWE states that the provisions of its contracts with Citizens and TOUA will continue to be applied as if APS continued to own the generation. Thus, to the extent APS generation costs would have determined the SIC value, the appropriate monthly charge to SIC customers for generation from the transferred APS facilities will not be based on rates negotiated by or between the Pinnacle West Companies. PWE states that energy charges for transferred APS generation will be passed through to wholesale SIC customers in accordance with the terms of the applicable SIC provisions of the customer's contract, not at some higher rate negotiated by or between PWE, PWCC

[17] See First Energy Trading & Power Marketing, Inc., 84 FERC ¶ 61,214 at 62,037 (1998); GPU Advanced Resources, Inc., 81 FERC ¶ 61,335 at 62,539 (1997); Detroit Edison Company, et al., 80 FERC ¶ 61,348 at 62,197 (1997).

and APS.[18] We find that PWE's explanation adequately resolves the concerns raised by Citizens and TOUA.

In PWCC, the Commission found PWCC's proposal to cap SIC prices at levels based on the Palo Verde Index a reasonable means to avoid potential affiliate abuse. The Commission stated that, as is the general practice in the industry, these rates are used to price coordination transactions that occur on an "as-available basis" when both parties can agree on a price that satisfies each party's own economic interests.[19] The Commission stated that the four rate schedules affected were APS's cost-based coordination sales tariff and bilateral agreements with three customers (Citizens, Colorado River Commission of Nevada, and TOUA) and that none of the customers had objected to Pinnacle's proposal.[20]

We find without merit Citizens' argument that the Palo Verde Index is inadequate to protect against affiliate abuse by the Pinnacle West Companies. The Commission has repeatedly held that capping the pass-through of prices resulting from affiliate transactions by reference to competitive prices at recognized market hubs provides an effective mechanism to prevent affiliate abuse.[21] Citizens has failed to persuade us that the Palo Verde Index is not a recognized market hub with competitive prices or that this safeguard would not be adequate to prevent affiliate abuse under the circumstances at issue here.[22]

Based on the protections against affiliate abuse accepted in Docket No. ER00-2268-000, wholesale customers with SIC provisions in their contracts receive the benefit of the actual APS SIC or the Palo Verde Index, whichever is lower. Thus, we agree with PWE that, where APS's traders hedge and beat the market, there will be a direct benefit to

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[18]PWE September 5 Answer at 5-6.

[19]PWCC, 91 FERC at 61,998.

[20]Id. at n.18.

[21]See First Energy Trading Services, Inc., 88 FERC ¶ 61,067 (1999); AYP Energy, Inc., 87 FERC ¶ 61,009 at 61,022(1999); PWCC, 91 FERC at 61,998.

[22]In PWCC, the Commission stated that it was satisfied by PWCC's proposal to cap SIC prices based on the Palo Verde Index "because the Palo Verde Index is an open, transparent, well-recognized index of market prices in the Palo Verde region and because [PWCC] does not control prices under the Palo Verde Index." PWCC, 91 FERC at 61,998.

Citizens and other SIC customers; where APS's traders do not beat the market (due to generation outages or otherwise), the Palo Verde Index may provide a buffer against excessive prices that protects the interests of APS's SIC customers.

As noted above, Tucson and Arizona Districts each reiterate in this proceeding arguments they raised in Docket No. ER00-2268-000 and that we addressed in PWCC, 91 FERC at 61,999. Thus, we will not revisit those issues here. Moreover, Tucson's arguments are more appropriately addressed on rehearing in PWCC.[23]

For the foregoing reasons, we will approve PWE's request to make sales at market-based rates to its affiliates, including its proposed code of conduct.

5. Ancillary Services

PWE requests authority to engage in the sale of certain ancillary services at market-based rates into the California ISO market.[24] We will grant PWE's request to make sales of ancillary services into the California ISO market at market-based rates.[25]

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[23]Arizona Districts did not seek rehearing of PWCC.

[24]PWE requests authority to provide the following ancillary services into the California ISO at market-based rates: Regulation and Frequency Response Service, Energy Imbalance Service, Operating Reserve - Spinning Reserve Service, and Operating Reserve - Supplemental Reserve Service. See Pinnacle Application, Exhibit B (Proposed APS Market-Based Tariff at p.2).

As noted above, Arizona Districts raise the same objections to PWE's request to engage in ancillary service sales into the California ISO at market-based rates that it raised with regard to PWCC's similar request in Docket No. ER00-2268-000. The Commission fully addressed Arizona Districts' objections in PWCC, 91 FERC at 61,999, and Arizona Districts did not seek rehearing of the Commission's resolution of those issues in that proceeding. Accordingly, we will not revisit those issues here.

[25]See AES Redondo Beach, L.L.C., et al., 85 FERC ¶ 61,123 (1998), order on reh'g, 87 FERC ¶ 61,208 (1999).

ORIGINAL

1800 M Street, N.W.
Washington, D.C. 20036-5869
202-467-7000
Fax: 202-467-7176

Morgan, Lewis & Bockius LLP
COUNSELORS AT LAW

Mary Ann K. Huntington
202-467-7622

ER 97-1672-000

February 12, 1997

OFFICE OF THE SECRETARY FILED
97 FEB 12 P 3:37
FEDERAL ENERGY REGULATORY COMMISSION

Lois D. Cashell
Secretary
Federal Energy Regulatory Commission
888 First Street, N.E.
Washington, D.C. 20426

Re: Arizona Public Service Company, Docket No. ER97-___-000

Dear Ms. Cashell:

Pursuant to Rule 205 of the Rules of Practice and Procedure of the Federal Energy Regulatory Commission, please find enclosed for filing on behalf of Arizona Public Service Company ("APS") an original and fourteen (14) copies of APS's Application for Order Approving Market-Based Rates. Also enclosed is diskette containing a Notice of Filing suitable for publication in the Federal Register.

If you have any questions regarding the enclosed Application, please call me at (202) 467-7622.

Very truly yours,

Mary Ann K. Huntington
Attorney for
Arizona Public Service Company

Enclosures

cc: Thomas Parrish

FERC DOCKETED
FEB 12 1997

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ER 97-1672-000

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Arizona Public Service Company	)	Docket No. ER97- -000

97 FEB 12 PM 3:37

APPLICATION OF ARIZONA PUBLIC SERVICE COMPANY FOR ORDER APPROVING MARKET-BASED RATES

Pursuant to Rule 205 of the Federal Energy Regulatory Commission's ("Commission's") Rules of Practice and Procedure, 18 C.F.R. § 385.205 (1996), Arizona Public Service Company ("APS") submits this application for authorization to engage in wholesale, bulk power sales at market-determined prices, including sales not involving APS's generation or transmission. Specifically, APS requests that the Commission (1) accept and approve APS's market-based Market Rate Tariff No. 1 ("Market Tariff"), attached hereto as Exhibit A, (2) grant blanket authorizations for APS to make wholesale sales of electric power at rates to be negotiated with the purchaser; and (3) waive the Commission's filing requirements, as necessary. Pursuant to Section 35.3(a) of the Commission's regulations, APS requests an effective date of 60 days after this filing, or the date on which the Commission issues an order approving APS's application for market-based rates, whichever is earlier.

I. BACKGROUND

APS is a public utility company incorporated under the laws of Arizona. APS owns, operates and controls facilities located in the state of Arizona used for the generation, transmission, and distribution of electric power. APS is seeking authorization to engage in wholesale, bulk power marketing activities at negotiated rates. APS plans to engage in sales of its own generation, and may

engage in purchase and resale transactions involving electric energy and capacity purchased from other public utilities, power producers, and power marketers. APS's Market Tariff allows it to make sales of energy and capacity to unaffiliated entities at market-based rates.

II. COMMUNICATIONS

Communications regarding this Application should be directed to the following individuals:

Thomas E. Parrish, Esq.
Law Department
Arizona Public Service Company
P.O. Box 53999
Station 9820/18th Floor
Phoenix, AZ 85072-3999
(602) 250-3625

John D. McGrane, Esq.
Mary Ann Huntington
Morgan, Lewis & Bockius LLP
1800 M Street, NW
Washington, D.C. 20036
(202) 467-7621/7622

Joel R. Spitzkoff
Federal Regulation
Arizona Public Service Company
P.O. Box 53999
Station 9860/18th Floor
Phoenix, AZ 85072-3999
(602) 250-2949

Copies of this filing have been mailed to the Arizona Corporation Commission.

III. LIST OF MATERIALS SUBMITTED WITH THIS FILING

The following is a list of materials APS has submitted with its application for market-based rates:

Exhibit A - APS's market-based Market Rate Tariff No. 1, including a Form of Service Agreement

Exhibit B - A Market Power analysis for APS

Exhibit C - A Notice of Filing suitable for publication in the Federal Register

IV. REQUEST FOR MARKET-BASED RATE APPROVAL

Historically, the Commission has required APS and other jurisdictional public utilities to develop their rates based on their "cost of service." As more competition has developed in the wholesale power market, the Commission has been willing to accept rates that are negotiated between the parties without requiring cost support by the seller. In light of the rapid changes occurring in the electric utility industry, APS wants additional flexibility in pricing its wholesale power sales and, therefore, seeks authorization to make such sales at negotiated market-based rates, pursuant to the enclosed Market Tariff.

The Commission generally will allow an entity -- whether a public utility, an independent power producer, or a power marketer -- to charge market-based rates if it can demonstrate that neither it nor any of its affiliates has, or has adequately mitigated market-power in generation and transmission and neither can erect barriers to entry. In evaluating requests for market-based rates, the Commission also considers whether there is any evidence of affiliate abuse or reciprocal dealing. In a number of recent cases, the Commission has set forth the criteria that must be satisfied in order for a jurisdictional entity to receive authorization to charge market-based rates. The Commission has explained the current standards for market-based rates as follows:

> The Commission's general standard is to allow market-based rates if the seller (and each of its affiliates) does not have, or has adequately mitigated market power in generation and transmission and cannot erect other barriers to entry. In addition, the Commission considers whether there is evidence of affiliate abuse or reciprocal dealing . . . In evaluating requests for open-ended, market rate authority, the

> Commission uses these same general standards but also implements reporting and independent review requirements because it will not have the opportunity to examine the particular circumstances of each transaction.

Heartland Energy Service, Inc., 68 FERC ¶ 61,223, at 62,060 (1994). The Commission uses these criteria to evaluate the market-based rate applications of traditional electric utilities, as well as power marketers. *See Southwestern Public Service Co.*, 72 FERC ¶ 61,208 (1995); *Maine Public Service Co.*, 71 FERC ¶ 61,249 (1995). As demonstrated herein, APS meets the Commission's criteria and should be granted authority to engage in transactions at market-based rates.

A. Generation Market Power

With respect to its generation market power concerns, the Commission generally requires that an entity (1) demonstrate that the entire output of its or any of its affiliates' generating facilities is committed under a long-term contract; (2) demonstrate that it and its affiliates already are authorized to sell power at market-based rates; or (3) submit a market analysis that indicates that neither it nor its affiliates have generation dominance in the relevant markets. *LG&E Power Marketing, Inc. et al.*, 68 FERC ¶ 61,247, at 62,121 (1994). The Commission has explained:

> When evaluating generation dominance for a traditional investor-owned electric utility, an affiliated power producer or an independent power producer that proposes to sell at market-based rates on an open-ended basis, the Commission defines the geographic markets as those utilities directly interconnected to the seller (first tier markets). Affiliated power marketers may sell in these same markets or in other markets. To guard against the possibility that an affiliated marketer's rates would be affected by the generation dominance of an affiliated public utility, the affiliated power marketer needs to provide a market analysis of the relevant market of its affiliates that own generating assets. If the market analysis shows no generation dominance for the affiliates, there would be no reason to ascribe generation dominance to the affiliated power marketer in the same market or in any other (more remote) markets.

Heartland, 68 FERC at 62,061 (footnotes omitted); *see also Detroit Edison* Co., 77 FERC ¶ 61,279, slip op. at 2 (Dec. 19, 1996); *PacifiCorp.*, 77 FERC ¶ 61,280, slip op. at 2 (Dec. 19, 1996); *Progress Power Marketing, Inc.*, 76 FERC ¶ 61,155, at 61,919 (1996); *Northwest Power Marketing Company, L.LC.*, 75 FERC ¶ 61,281, at 61,889 (1996).

APS is engaged in the generation, transmission and distribution of electric energy and capacity in a franchised electric service territory. To address the Commission's requirements concerning generation market power, APS has submitted with this filing a market power analysis, attached as Exhibit B, which demonstrates that APS does not have generation market power.

Consistent with the Commission's requirements, APS's market-power analysis considers total and uncommitted capacity in APS's first tier markets. APS's share of total generating capacity and uncommitted or surplus capacity in each first tier market was determined using data from the Western Systems Coordinating Council ("WSCC") 1996 Loads and Resources Report. Additional information from the following sources was also utilized in preparing APS's market power analysis: (1) "1995 WSCC Existing Generation" database; (2) RDI "POWERDAT" database; and (3) "WSCC 1995 Coordinated Bulk Power Supply Program (1994-2004)" report. In determining uncommitted capacity, a reserve margin of 6% to 25% was used for all of the first and second tier entities. The reserve margin data was obtained from the WSCC 1995 Coordinated Bulk Power Supply Program (1994-2000) report. If information on an individual company's reserve margin was not available, then the summer, subregional power area average was used for that utility.

The market power analysis demonstrates that APS does not have market power. After the effects of APS's open access transmission tariff are taken into account, APS's share of total

capacity in the first tier markets ranges from 3% to 7%; APS's share of uncommitted capacity is 0%. These figures are well within the range the Commission has approved for market-based rates.

In addition to APS's own generation, the market power analysis concludes that APS's expected external power marketing activities do not raise generation market power concerns. The market power study explains that with the availability of open access transmission service, entry by those who would market power on a buy-and-sell basis is relatively easy; therefore, power marketing does not raise concerns about the exercise of market power. As a result, APS requests that the Commission grant its request to sell power at market-based rates.

B. Transmission Market Power

In order to ensure that utilities do not possess transmission market power, the Commission generally requires a public utility have on file an open access transmission tariff for the provision of comparable services *See, e.g., Southern Indiana Gas & Electric Company*, 77 FERC ¶ 61,021 (1996).

On July 9, 1996, APS filed in Docket No. OA96-153-000 an open-access transmission tariff providing for comparable services.

C. Barriers to Entry

In addition to generation and transmission market power, the Commission also analyzes whether the entity seeking market-based rates owns or controls other potential barriers to entry. In prior cases, the Commission has indicated that it also will consider whether the entity is affiliated with, or owns, interstate gas pipelines or local gas distribution systems.

APS is not affiliated with any entities that could impose barriers to entry in the electric power generation business through their ownership or control of any resources or inputs that could be essential to market entry by competitors. *See* Exhibit B, APS's Market Power Analysis.

D. Affiliate Abuse and Reciprocal Dealing

In evaluating market-based rate applications of affiliated power marketers, the Commission also considers the potential for affiliate abuse and reciprocal dealing. The Commission has explained that affiliate abuse takes place when a public utility and an affiliated power marketer transact in ways that result in a transfer of benefits from the public utility (and the ratepayers) to the power marketer (and the shareholders). *Heartland*, 68 FERC at 62,062; *Wholesale Power Services, Inc.*, 72 FERC ¶ 61,284 (1995).

In this instance, there is no affiliated power marketer seeking market-based rates. APS itself is seeking market-based rates for its own wholesale power sales, including sales not involving APS's transmission or generation facilities. For this reason, there is no affiliate abuse issue in this proceeding. *See Southwestern Service Co.*, 72 FERC ¶ 61,208, at 61,968 (1995).

E. The Commission's Filing Requirements

In *Southern Company Services, Inc.*, 75 FERC ¶ 61,130 (1996), the Commission revised its filing requirements for public utilities engaged in market-based sales. Consistent with the Commission's requirements in Southern, APS commits that it will file quarterly transaction summaries of short-term transactions (transactions with a duration of one year or less) entered into under APS's Market Tariff. For short-term transactions, APS will list the purchaser, the transaction period, the unbundled prices for generation, transmission, and ancillary services, the amount of electricity sold, and the total charge to the purchaser. For long-term transactions (those with a duration of more than

one year), APS will file the transaction agreement within 30 days of commencement of service. *Prior Notice and Filing Requirements Under Part II of the Federal Power Act*, 64 FERC ¶ 61,139, *clarified*, 65 FERC ¶ 61,081 (1993). For both the quarterly summaries and the service agreements for long-term transactions, APS will separately state the unbundled prices for generation, transmission, and ancillary services, as required by the Commission. *See Cincinnati Gas & Electric Co.*, 77 FERC ¶ 61,172, slip op. at 5 (Nov. 15, 1996). Additionally, to facilitate the orderly maintenance of the Commission's files, APS will file its long-term transactions separately from its short-term transactions.

With respect to electricity price risk management transactions (*e.g.*, futures, options, swaps) that allow customers to control or mitigate adverse fluctuations in the price of electricity, the Commission has noted that while many such contracts obligate the selling company to deliver electricity upon the customer's demand, frequently the customer may decide not to exercise its contractual right to take delivery. As a result, APS will only file transactions which actually go to delivery. *New York Mercantile Exchange*, 74 FERC ¶ 61,131 (1 996).

APS commits that it will file a revised market analysis every three years. This is consistent with Commission precedent. *Morgan Stanley Capital Group, Inc.*, 69 FERC ¶ 61,175, at 61,695 (1994) (as clarified in *Engelhard Power Marketing, Inc.*, 70 FERC ¶ 61,250(1995)).

V. OTHER INFORMATION

APS is unable to determine the level of use of its Market Tariff; therefore, APS cannot provide an estimate of revenues.

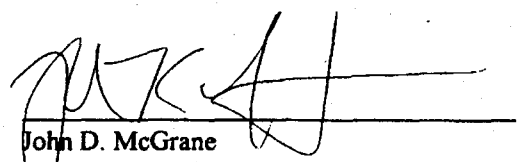
There are no expenses or costs included in the proposed rates that have been judged in any administrative or judicial proceedings to be illegal, duplicative, or unnecessary costs that are demonstrably the product of any discriminatory employment practices.

APS respectfully requests that the Commission accept the Market Tariff for filing and permit it to become effective 60 days from the date of this filing, or the date of the Commission's order accepting APS's request for market-based rate approval, whichever is earlier. Because APS has requested market-based rate authority, many of the Commission's filing requirements are inapplicable. To the extent any filing requirement is not satisfied by the material enclosed herewith, APS requests a waiver of any additional filing requirements in Part 35 of the Commission's regulations which may be necessary to permit implementation of the Market Tariff in accordance with its terms.

VI. CONCLUSION

WHEREFORE, for the foregoing reasons, APS requests the Commission to issue an order that grants authorization for APS to make wholesale sales of electric power at market-based rates, including sales not involving APS's generation or transmission. APS requests an effective date 60 days from the date of this filing, or the date of the Commission's order accepting APS's request for market-based rate approval, whichever is earlier.

Respectfully submitted,



John D. McGrane
Mary Ann Huntington
Michael P. Donahue
Morgan, Lewis & Bockius, LLP
1800 M Street, NW
Washington, D.C. 20036
(202) 467-7000

Thomas E. Parrish, Esq.
Law Department
Arizona Public Service Company
P.O. Box 53999
Station 9820/18th Floor
Phoenix, AZ 85072-3999
(602) 250-3625

Dated: February 12, 1997

ARIZONA PUBLIC SERVICE COMPANY
MARKET RATE TARIFF NO. 1
(MR-1)

1 **DEFINITIONS**

The following terms shall have the specified meaning when used in the Market Rate Tariff No. 1 ("Tariff") or in a Service Agreement

1.1 **Commission:** The Federal Energy Regulatory Commission.

1.2 **Customer:** An entity that executes a Service Agreement under this Tariff.

1.3 **Service Agreement:** The initial agreement and any supplements thereto entered into by a Customer and Arizona Public Service Company ("APS") for service under this Tariff.

1.4 **Tariff:** This Market Rate Tariff No. 1 as it may be amended and/or superseded from time to time.

1.5 **Transaction:** An individual transaction scheduled pursuant to this Tariff and a Service Agreement.

2 **AVAILABILITY**

2.1 This Tariff is available for purchases of electric energy and/or capacity from APS.

2.2 No entity affiliated with APS is eligible for service under this Tariff.

3 **CHARACTER OF SERVICE**

APS may provide capacity and/or energy under this Tariff in varying amounts, at varying levels of firmness or priorities of service, for varying periods of service, and in accordance with varying delivery schedules, as agreed to between the Customer and APS.

4 **RATES**

4.1 The rates for purchases under this Tariff shall be as agreed to by the Customer and APS.

4.2 Should APS obtain transmission service under its Open Access Transmission Tariff for sales under this Tariff, it will separately state the prices for wholesale generation, transmission and ancillary services.

5 **SERVICE AGREEMENTS**

5.1 Prior to the commencement of service to a new customer, APS and each new Customer will execute a Service Agreement. APS will file a copy of the executed Service Agreement with the Commission.

5.2 APS may refuse, at its sole discretion, to enter into a Service Agreement or Transaction under this Tariff. APS is under no obligation to execute a Service Agreement to provide service hereunder.

5.3 Acceptance of service by the Customer pursuant to a Service Agreement commits the Customer to the provisions of this Tariff and to the terms of the Service Agreement.

6 **EXPANSION OF FACILITIES**

APS will have no obligation under this Tariff or any Service Agreement executed hereunder to plan its system, to enlarge or modify its facilities or operate its system in such a manner in order to provide or maintain energy and/or capacity sold hereunder.

FORM OF SERVICE AGREEMENT

This Service Agreement, dated as of _____, is entered into by and between Arizona Public Service Company ("Company"), and _____ ("Customer"), pursuant to the Company's Market Rate Tariff No. 1 ("Tariff").

Each transaction hereunder shall be carried out under terms and conditions as agreed upon by the Company and Customer in accordance with the terms and conditions of the Tariff.

IN WITNESS WHEREOF, Company and Customer have caused this Service Agreement to be executed by their respective authorized officials as of the date first above written.

ARIZONA PUBLIC SERVICE COMPANY	_____
By: _____	By: _____
Title: _____	Title: _____
Date: _____	Date: _____

EXHIBIT B

Arizona Public Service Company's
Generation Market Power Analysis

The Federal Energy Regulatory Commission ("FERC") has required those requesting the right to make wholesale bulk power sales at market-determined prices to document that they do not possess either *transmission market power* or *generation dominance*. Concerning the first of these, FERC has found that concerns about what is called *transmission market power* can be eliminated by the filing of an open access transmission tariff that meets its comparability requirements. With the Final Rule in Docket No. RM95-8-000, *Promoting Wholesale Competition Through Open Access Non-Discriminatory Transmission Services By Public Utilities and Recovery of Stranded Costs by Public Utilities and Transmitting Utilities*, FERC Stats. & Regs. ¶ 31,026 (1996) ("Order No. 888"), all jurisdictional utilities were required to file such tariffs, and so this seemingly no longer has significance as a separate requirement for granting market-based pricing authority. Arizona Public Service Company ("APS") already has filed such a tariff. Concerning the second, *generation dominance*, FERC's approach for assessing the appropriateness of market-based pricing for wholesale bulk power sales from existing capacity has been to look at the applicant's shares of total and uncommitted generating capacity within various *first tier markets*.[1/] FERC's approach for assessing the appropriateness of market-based pricing for wholesale bulk power sales from new capacity is to examine whether the applicant for market-based pricing authority controls entry barriers that might be used to thwart potential competitors. This exhibit, including its attached tables,

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1/ The analysis examines APS's share of total and uncommitted generator capacity with APS' first tier and second tier markets.

provides, in support of APS's application for market-based pricing authority, the types of analyses which FERC has required.

FIRST TIER ANALYSES

As indicated, FERC's approach for assessing the appropriateness of market-based pricing for sales from existing capacity has been to look at the applicant's share of total and uncommitted capacity within various first tier markets. A first tier utility is one that is directly interconnected with the applicant. The participants in each first tier market, sometimes called a hub and spoke market, include (i) the utility on whom the market is centered, (ii) the applicant for market-based pricing, (iii) each utility other than the applicant that is interconnected with the center utility, and (iv) any other utility that can be accessed by the applicant's open access transmission tariff.[2/] For such analyses, total capacity generally is considered to be the sum of owned capacity plus firm purchases net of firm sales, while uncommitted capacity is the excess of the company's total capacity over the sum of its peak demand plus reserve responsibility. Consistent with the Commission's requirements, APS's market-power analysis considers total and uncommitted generating capacity in APS's first tier markets.

The utilities interconnected with APS are as follows: Arizona Electric Power Cooperative, Inc. ("AEPC"), Colorado River Indian Irrigation Project ("CRIP"), El Paso Electric Company ("EPE"), Electrical and Irrigation Districts ("ED/ID"),[3/] Imperial Irrigation District ("IID"),

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2/ With the issuance of Order No. 888 and its requirement that all jurisdictional utilities file open access transmission tariffs, this category seemingly should be revised to include all utilities accessible by payment of but a single wheeling charge, and not just those accessible by a single wheeling charge over the applicant's system.

3/ ED/ID consists of: Aguila Irrigation District ("AID"), Buckeye Water Conservation & (continued...)

Los Angeles Department of Water & Power ("LADWP"), Navajo Tribal Utility Authority ("NTUA"), Nevada Power Company ("NEVP"), PacifiCorp-West ("PAC-W"), PacifiCorp-East ("PAC-E"), Plains Electric Generation & Transmission Cooperative ("Plains"), Public Service Company of New Mexico ("PNM"), Salt River Project ("SRP"), San Diego Gas & Electric Company ("SDG&E"), Southern California Edison Company ("SCE"), Southern California Public Power Association ("SCPPA"), Tohono O'Odham Utility Authority ("TOUA"), Tri-State G&T Association, Inc. ("TSGT"), Tucson Electric Power Company ("TEP"), United States Bureau of Reclamation-Lower Colorado River ("USLC"), United States Bureau of Reclamation-Upper Colorado River-NW ("USUCNW"), United States Bureau of Reclamation-Upper Colorado River-RM ("USUCRM"), Western Area Power Administration-Lower Colorado River ("WAUC"), Western Area Power Administration-Lower Colorado River ("WALC"), Wickenburg Electrical Department ("WED"), and Williams ("WMS").

The results of the first tier analyses are summarized in Tables 1, 2, and 3 attached hereto. Table 1 contains information on total installed capacity, firm load, firm purchases, firm sales, planning reserve margin (the percent of total capacity that is reserves and the amount of reserves), and uncommitted capacity for each first and second tier entity; Table 2 contains an analysis of each first tier target market; and Table 3 contains a summary of APS's market share of total installed and uncommitted capacity.

3/(...continued)
Drainage District ("BWCD"), Electrical District No. 1 ("ED1"), Electrical District No. 3 ("ED3"), Electrical District No. 7 ("ED7"), Electrical District No. 8 ("ED8"), Harquahala Valley Power District ("HVPD"), Maricopa County Municipal Water Conservation District No. 1 ("MCM"), McMullen Valley Water Conservation & Drainage District ("MVD"), Roosevelt Irrigation District ("RID"), and Tonopah Irrigation District ("TID").

and after the effects of the open access tariff have been incorporated. Under either analysis, APS's figures are far below those which might suggest concern about the potential exercise of market power under either FERC precedent or any other reasonable standard.

ENTRY BARRIERS

The above analyses implicitly assume that all of APS's sales under market-based pricing authority will involve its own generation or transmission. However, APS also may make sales under this authority that do not involve its own generation or transmission. Such sales do not present any concerns about the possible exercise of market power. Ease of entry is one of the most important factors to consider in assessing the potential for the exercise of market power. Where entry is relatively easy, concerns about the potential exercise of market power should vanish. With the advent of open access transmission tariffs, entry by those who would market electric capacity on a buy-and-resell basis, as APS may do, is relatively easy. It requires access to those transmission tariffs, knowledge of supply and demand sources, and perhaps an ability to recognize various types of risk and provide mechanisms to hedge these, but it does not require various types of capital investments in generation or transmission plant that in the past might have been used to argue that entry was difficult. In short, there are potentially many entities that could compete with APS in the marketing of capacity on an simultaneous buy-and-resell basis. Stated differently, with the advent of open access transmission tariffs, power marketing does not possess the characteristics of an activity where there are likely to be realistic concerns about the exercise of market power.

In the past, FERC's analyses of potential barriers have focused on control of sites at which new generation might be constructed, control of fuel supplies and control of fuel transport facilities. As a general matter, a single firm is unlikely to have sufficient control in any of these areas

to enable it to thwart entry by its competitors. The specific facts indicate that such control is not present in this case. APS plans to install a combustion turbine near Kingman, Arizona in 1998 to serve the load of Citizens Utilities Company ("CUC") in the Kingman area and which cost will be directly assigned to CUC. However, at this time, there is no firm commitment to install additional APS owned generation resources. Additionally, APS does not have ownership in or control of any fossil fuel or nuclear fuel resources. Finally, as a joint participant in the Navajo Generating Station, APS has partial ownership interest in the railroad that delivers coal from the mine to the plant (including the locomotive, coal cars and approximately 80 miles of track). Other than this, APS does not have, in part or whole, any ownership interest in fuel transportation facilities.

FERC RIMS DOC 177212

TABLE 1
GENERATION POWER MARKET ANALYSIS
DATA SUMMARY [1]

ENTITY	1	2	3	4	5	6	7
					Planning Reserve Margin		
	Total Installed Capacity [2]	Firm Load [3]	Firm Purchases [4]	Firm Sales [4]	Percent [5]	Amount [2*5]	Uncommitted Capacity [6] [1+3-(2+4+6)]
ARIZONA PUBLIC SERVICE CO.	3,943	4,024	537	454	16%	644	-
							-
FIRST-TIER ENTITIES							-
ARIZONA ELECTRIC PWR COOP INC (AEPC)	520	586	298	100	16%	94	38
COLORADO RIVER INDIAN IRRIGATION PROJECT (CRIIP)	-	6	6	-	13%	1	-
EL PASO ELECTRIC CO. (EPE)	1,486	1,088	120	314	13%	141	63
ELECTRICAL and IRRIGATION DISTRICTS (ED/ID) (7)	-	163	163	-	13%	21	-
IMPERIAL IRRIGATION DISTRICT (IID)	653	630	405	4	15%	95	330
LOS ANGELES DEPT OF WATER & POWER (LDWP)	7,516	5,209	179	148	16%	807	1,531
NAVAJO TRIBAL UTILITY AUTHORITY (NTUA)	-	126	126	-	13%	16	-
NEVADA POWER CO. (NEVP)	2,994	3,316	315	-	15%	497	-
PACIFICORP-WEST (PAC-W)	6,833	7,388	-	225	11%	813	-
PACIFICORP-EAST (PAC-E)	938	-	255	635	11%	-	558
PLAINS ELECTRIC GEN & TRANS COOP (PEGT)	235	377	148	-	18%	68	-
PSC OF NEW MEXICO (PNM)	1,497	1,202	248	199	20%	240	103
SALT RIVER PROJECT (SRP)	4,086	4,114	1,143	371	16%	658	86
SAN DIEGO GAS & ELECTRIC CO. (SDGE)	3,055	3,260	1,133	-	15%	489	439
SOUTHERN CALIFORNIA EDISON CO. (SCE)	18,237	17,209	1,543	3	16%	2,753	-
SOUTHERN CALIFORNIA PUBLIC POWER ASSOCIATION (SCPPA)	739	-	-	739	0%	-	-
TOHONO O'ODHAM UTILITY AUTHORITY (TOUA)	-	14	14	-	13%	2	-
TRI-STATE G & T ASSN, INC. (TSGT)	1,256	1,099	763	533	15%	165	222
TUCSON ELECTRIC POWER CO. (TEP)	1,948	1,682	415	295	15%	252	134
US BUREAU OF RECLAMATION-LOWER COLORADO RIVER (USLC)	547	-	-	547	6%	-	-
US BUREAU OF RECLAMATION-UPPER COLORADO RIVER-NW (USUC)	-	-	-	-	11%	-	-
US BUREAU OF RECLAMATION-UPPER COLORADO RIVER-RM (USUC)	-	-	-	-	15%	-	-
WESTERN AREA POWER ADMIN.-LOWER COLORADO RIVER (WALC)	457	71	227	37	6%	4	572
WESTERN AREA POWER ADMIN.-UPPER COLORADO RIVER (WAUC)	1,807	7	-	1,183	15%	1	616
WICKENBURG ELECTRICAL DEPARTMENT (WED)	-	6	6	-	13%	1	-
WILLIAMS (WMS)	-	3	3	-	13%	0	-
TOTAL	58,747	51,580	8,047	5,786		7,764	1,663
ARIZONA PUBLIC SERVICE CO. / TOTAL	6.7%						0.0%

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TABLE 1
GENERATION POWER MARKET ANALYSIS
DATA SUMMARY [1]

ENTITY	1 Total Installed Capacity [2]	2 Firm Load [3]	3 Firm Purchases [4]	4 Firm Sales [4]	5 Planning Reserve Margin Percent [5]	6 Planning Reserve Margin Amount [2*5]	7 Uncommitted Capacity [6] {1+3-(2+4+6)}
SECOND-TIER ENTITIES							
ANAHEIM PUBLIC UTILITIES DEPT. (ANHM)	377	-	96	-	16%	-	473
ARIZONA POWER AUTHORITY (APA)	400	15	-	362	0%	-	23
ARKANSAS RIVER POWER AUTHORITY (ARPA)	75	58	38	-	15%	9	46
AZUSA (AZSA)	32	-	30	-	16%	-	62
BANNING (BNNG)	22	-	14	-	16%	-	36
BASIN ELECTRIC POWER COOPERATIVE (BEPC)	651	278	43	225	15%	42	149
BASIN ELECTRIC POWER COOPERATIVE (BEPC)	-	-	-	-	15%	-	-
BLACK HILLS CORP. (BHPL)	299	306	104	6	15%	46	45
BONNERS FERRY, CITY OF (BF)	-	-	-	-	11%	-	-
BONNEVILLE POWER ADMIN (BPA)	1,351	11,549	315	369	11%	1,270	-
BURBANK PUBLIC SERVICE DEPT. (BURB)	354	245	50	5	20%	49	105
CALIFORNIA DEPT-WTR RESOURCES (CDWR)	1,838	1,123	637	212	10%	112	1,027
CENTRAL CALIFORNIA POWER AGENCY (CCPA)	122	-	-	23	16%	-	99
CENTRALIA LIGHT DEPARTMENT (CC)	-	-	-	-	11%	-	-
CENTURY POWER CORPORATION (CPC)	-	-	-	40	13%	-	-
CITIZENS UTILITY COMPANY (CUC)	45	239	239	-	16%	38	7
COLORADO SPRINGS UTILITIES (CSU)	536	578	140	-	15%	87	11
COLTON (CLTN)	2	-	31	-	16%	-	33
COMISION FEDERAL DE ELECTRICDAD (CFE)	1,330	1,104	140	220	15%	166	-
COMISION FEDERAL DE ELECTRICDAD (MEX)	-	-	-	-	15%	-	-
DESERET GENERATION & TRAN COOP (DGT)	520	222	102	107	11%	24	269
EUGENE WATER & ELECTRIC BOARD (EWEB)	127	473	-	-	11%	52	-
FARMINGTON ELECTRIC UTILITY (FARM)	125	105	21	-	13%	14	27
GLENDALE PUBLIC SERVICE DEPT. (GLEN)	345	275	70	-	25%	69	72
HOWELL POWER SYSTEMS, INC. (HOW)	-	-	-	-	13%	-	-
IDAHO POWER CO. (IPC)	2,646	2,393	-	1	11%	263	-
INTERMOUNTAIN CONSUMER POWER AASSOCIATION (ICPA)	338	-	-	-	11%	-	338
LOS ALAMOS COUNTY UTILITIES (LAC)	89	80	32	-	13%	10	31
M-S-R PUBLIC POWER AGENCY (MSR)	143	-	-	-	16%	-	143
METROPOLITAN WATER DISTRICT (MWD)	154	290	-	21	16%	45	-
MODESTO IRRIGATION DISTRICT (MID)	283	502	489	-	16%	78	192
MONTANA POWER CO. (MPC)	1,585	1,397	-	81	11%	154	-
MUNICIPAL ENERGY AGENCY FO NEBRASKA (MEAN)	38	94	67	-	15%	14	-

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TABLE 1
GENERATION POWER MARKET ANALYSIS
DATA SUMMARY [1]

ENTITY	1	2	3	4	5	6	7
					Planning Reserve Margin		
	Total Installed Capacity [2]	Firm Load [3]	Firm Purchases [4]	Firm Sales [4]	Percent [5]	Amount [2*5]	Uncommitted Capacity [6] [1+3-(2+4+6)]
SECOND-TIER ENTITIES CONTINUED							
NAVAJO AGRICULTURAL PRODUCTS INDUSTRY (NAPI)	-	16	16	-	13%	2	-
NEBRASKA PUBLIC POWER DISTRICT (NPPD)	-	-	-	-	15%	-	-
NORTHERN CALIFORNIA POWER AGENCY (NCPA)	404	628	-	192	16%	97	-
OKANOGAN PUBLIC UTILITY DISTRICT (OKPD)	-	-	-	-	11%	-	-
PACIFIC GAS & ELECTRIC CO. (PG&E)	17,414	16,532	1,833	767	16%	2,562	-
PASADENA WATER & POWER DEPT. (PASA)	327	264	42	-	15%	40	66
PLATTE RIVER POWER AUTHORITY (PRPA)	411	343	142	224	15%	51	-
PORTLAND GENERAL ELECTRIC CO (PGE)	2,284	3,315	877	315	11%	365	-
PSC OF COLORADO (PSC)	3,784	4,239	1,058	188	15%	636	-
PUD NO 1 OF CHELAN COUNTY (CHPD)	2,004	542	-	-	11%	60	1,402
PUD NO 1 OF COWLITZ COUNTY (COPD)	72	-	-	-	11%	-	72
PUD NO 1 OF DOUGLAS COUNTY (DOPD)	840	158	-	-	11%	17	665
PUD NO 1 OF GRAYS HARBOR CNTY (GHPD)	54	-	-	-	11%	-	54
PUD NO 1 OF PEND OREILLE CNTY (POPD)	75	-	-	-	11%	-	75
PUD NO 1 OF SNOHOMISH COUNTY (SHPD)	212	-	-	-	11%	-	212
PUD NO 2 OF GRANT COUNTY (GCPD)	1,967	464	-	-	11%	51	1,452
PUGET SOUND POWER & LIGHT CO. (PSPL)	2,545	4,134	-	-	11%	455	-
REDDING ELECTRIC DEPT. (RDNG)	29	184	187	-	16%	29	3
RIVERSIDE UTILITIES DEPT. (RVSD)	172	-	65	-	16%	-	237
ROCKY MOUNTAIN GENERATION COOPERATIVE (RMGC)	-	21	19	-	15%	3	-
SACRAMENTO MUNICIPAL UTIL DIST (SMUD)	835	2,240	1,301	-	16%	347	-
SAN CARLOS IRRIGATION PROJECT (SCIP)	-	26	-	-	13%	3	-
SAN FRANCISCO [CITY & COUNTY] (CCSF)	232	-	-	136	16%	-	96
SANTA CLARA ELECTRIC DEPT. (SNCL)	89	397	433	-	16%	62	64
SASKATCHEWAN POWER COMPANY (SPC)	-	-	-	-	15%	-	-
SEATTLE CITY LIGHT (SCL)	1,904	1,757	-	-	11%	193	-
SIERRA PACIFIC POWER CO (SPP)	1,118	1,151	-	160	11%	127	-
SOUTHWESTERN PUBLIC SERVICE COMPANY (SWPS)	-	-	-	-	15%	-	-
TACOMA PUBLIC UTILS-LIGHT DIV (TCL)	879	1,043	-	-	11%	115	-
TEXAS & NEW MEXICO POWER COMPANY (TNP)	-	222	126	-	13%	29	-
TRANSMISSION AGENCY OF NORTHERN CALIFORNIA (TANC)	-	-	-	-	16%	-	-
TURLOCK IRRIGATION DISTRICT (TID)	380	330	154	48	16%	51	105

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TABLE 1
GENERATION POWER MARKET ANALYSIS
DATA SUMMARY [1]

ENTITY	1	2	3	4	5	6	7
					Planning Reserve Margin		
	Total Installed Capacity [2]	Firm Load [3]	Firm Purchases [4]	Firm Sales [4]	Percent [5]	Amount [2*5]	Uncommitted Capacity [6] [1+3-(2+4+6)]
SECOND-TIER ENTITIES CONTINUED							
U.S. ARMY CORP OF ENGINEERS (USCE)	14,450	-	-	-	11%	-	14,450
U.S. DEPARTMENT OF THE INTERIOR (USDI)	-	-	-	-	16%	-	-
US BUREAU OF RECLAMATION-GREAT PLAINS (USGP)	-	-	-	-	15%	-	-
US BUREAU OF RECLAMATION-MID PACIFIC-CA (USMP)	1,257	-	-	1,052	16%	-	205
US BUREAU OF RECLAMATION-PACIFIC NORTHWEST (USPN)	7,107	-	-	-	11%	-	7,107
UTAH ASSOCIATED MUN POWER SYS (UAMP)	200	366	426	-	11%	40	220
UTAH MUNICIPAL POWER AGENCY (UMPA)	49	146	85	66	11%	16	-
VERNON MUNICIPAL LIGHT DEPT. (VERN)	43	-	40	-	16%	-	83
WASHINGTON WATER POWER CO. (WWPC)	1,759	1,540	-	-	11%	169	49
WESTERN AREA POWER ADMIN.-LOWER MONTANA (WALM)	819	64	427	926	15%	10	246
WESTERN AREA POWER ADMIN.-MID PACIFIC-CA (WAMP)	1	-	1,633	673	16%	-	961
WESTERN AREA POWER ADMIN.-MID PACIFIC-NW (WAMP)	45	-	-	-	11%	-	45
WESTERN AREA POWER ADMIN.-UPPER MONTANA (WAUM)	-	-	-	-	15%	-	-
WESTERN AREA POWER ADMIN.-UPPER MONTANA-NW (WAUM)	-	-	-	-	11%	-	-
WESTPLAINS ENERGY (WPE)	81	247	201	-	15%	37	-
WYOMING MUNICIPAL POWER AGENCY (WMPA)	23	35	11	-	15%	5	-
YUMA IRRIGATION DISTRICT (YID)	-	1	1	-	13%	0	-

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GENERATION POWER MARKET ANALYSIS
NOTES FOR TABLE 1

1. Data is from "Western Systems Coordinating Council (WSCC) 1996 Loads and Resources Report" unless specified otherwise.
2. Capacity is defined as the total installed generation (i.e., accredited capacity) and is at time of each entity's system peak.
   For the Northwest utilities, resource allocation amongst the utilities is from the "1995 WSCC Existing Generation" database.
3. The loads are actual system peak loads for 1995; except NTUA (1994) which is from the RDI "POWERDAT" database.
   For APS, this load is for retail customers served in the State of Arizona.
   The San Carlos Irrigation Project, SCIP, is included with AEPC.
   Welton-Mohawk Irrigation District and Yuma Irrigation District are included with WALC.
4. Firm purchases and sales include long-term contracts and short-term power arrangements and are at time of each entity's system peak.
5. The Planning Reserve Margin data is from the "WSCC 1995 Coordinated Bulk Power Supply Program (1994-2004)" report.
   If planning reserve margin data is unavailable for individual companies, then the summer, subregional power area average is used.
6. A dash indicates that the availability of reserve margin or uncommitted capacity is equal to zero or is less than zero.
7. The Electrical and Irrigation Districts are: Aguila Irrigation District (AID), Buckeye Water Conservation & Drainage District (BWCD), Electrical District No. 1 (ED1), Electrical District No. 3 (ED3), Electrical District No. 7 (ED7), Electrical District No. 8 (ED8), Harquahala Valley Power District (HVPD), Maricopa County Municipal Water Conservation District No. 1 (MCM), McMullen Valley Water Conservation & Drainage District (MVD), Roosevelt Irrigation District (RID), and Tonopah Irrigation District (TID).

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TABLE 2

MARKET 1 OF 22

ANALYSIS OF EACH FIRST-TIER TARGET MARKET

LINE		TOTAL INSTALLED CAPACITY	UNCOMMITTED CAPACITY
1	**FIRST-TIER ENTITY: AEPC**	520	38
	BEFORE OPEN ACCESS TRANSMISSION TARIFF (DIRECTLY INTERCONNECTED ENTITIES)		
2	APS	3,943	-
3	EPE	1,486	63
4	PNM	1,497	103
5	TNP	-	-
6	SRP	4,086	86
7	USLC	547	-
8	TEP	1,948	134
9	WALC	457	572
10	**SUB TOTAL (2 + ... + 9)**	13,964	957
11	**TOTAL (1 + 10)**	14,484	996
	AFTER OPEN ACCESS TRANSMISSION TARIFF (ADDITIONAL POTENTIAL MARKET PARTICIPANTS)		
12	CRIIP	-	-
13	ED/ID	-	-
14	IID	653	330
15	LDWP	7,516	1,531
16	NTUA	-	-
17	NEVP	2,994	-
18	PAC-W	6,833	-
19	PAC-E	938	558
20	PEGT	235	-
21	SDGE	3,055	439
22	SCE	18,237	-
23	SCPPA	739	-
24	TOUA	-	-
25	TSGT	1,256	222
26	USUC	-	-
27	USUC	-	-
28	WAUC	1,807	616
29	WED	-	-
30	WMS	-	-
31	**SUB TOTAL (11 + ... + 30)**	44,262	3,695
32	**TOTAL (11 + 31)**	58,747	4,691
	APS' SHARE OF TOTAL TARGET MARKET		
33	**BEFORE OPEN-ACCESS TARIFF (2 / 11)**	**27.2%**	**0.0%**
34	**AFTER OPEN-ACCESS TARIFF (2 / 32)**	**6.7%**	**0.0%**

TABLE 2

MARKET 3 OF 22

ANALYSIS OF EACH FIRST-TIER TARGET MARKET

LINE		TOTAL INSTALLED CAPACITY	UNCOMMITTED CAPACITY
1	**FIRST-TIER ENTITY: EPE**	1,486	63
	BEFORE OPEN ACCESS TRANSMISSION TARIFF (DIRECTLY INTERCONNECTED ENTITIES)		
2	APS	3,943	-
3	PAC-W	6,833	-
4	PAC-E	938	558
5	USUC	-	-
6	USUC	-	-
7	TSGT	1,256	222
8	WAUC	1,807	616
9	PEGT	235	-
10	PNM	1,497	103
11	TNP	-	-
12	SRP	4,086	86
13	TEP	1,948	134
14	AEPC	520	38
15	CPC	-	-
16	SCE	18,237	-
17	LDWP	7,516	1,531
18	SDGE	3,055	439
19	SCPPA	739	-
20	MEX	-	-
21	**SUB TOTAL (2 + ... + 20)**	52,610	3,727
22	**TOTAL (1 + 21)**	54,096	3,790
	AFTER OPEN ACCESS TRANSMISSION TARIFF (ADDITIONAL POTENTIAL MARKET PARTICIPANTS)		
23	CRIIP	-	-
24	ED/ID	-	-
25	IID	653	330
26	NTUA	-	-
27	NEVP	2,994	-
28	TOUA	-	-
29	USLC	547	-
30	WALC	457	572
31	WED	-	-
32	WMS	-	-
33	**SUB TOTAL (22 + ... + 32)**	4,651	901
34	**TOTAL (22 + 33)**	58,747	4,691
	APS' SHARE OF TOTAL TARGET MARKET		
35	**BEFORE OPEN-ACCESS TARIFF (2 / 22)**	**7.3%**	**0.0%**
36	**AFTER OPEN-ACCESS TARIFF (2 / 34)**	**6.7%**	**0.0%**

TABLE 2

MARKET 4 OF 22

ANALYSIS OF EACH FIRST-TIER TARGET MARKET

LINE		TOTAL INSTALLED CAPACITY	UNCOMMITTED CAPACITY
1	ED/ID	-	-
	BEFORE OPEN ACCESS TRANSMISSION TARIFF (DIRECTLY INTERCONNECTED ENTITIES)		
2	APS	3,943	-
3	**SUB TOTAL (2 + ... + 2)**	3,943	-
4	**TOTAL (1 + 3)**	3,943	-
	AFTER OPEN ACCESS TRANSMISSION TARIFF (ADDITIONAL POTENTIAL MARKET PARTICIPANTS)		
5	AEPC	520	38
6	CRIIP	-	-
7	EPE	1,486	63
8	IID	653	330
9	LDWP	7,516	1,531
10	NTUA	-	-
11	NEVP	2,994	-
12	PAC-W	6,833	-
13	PAC-E	938	558
14	PEGT	235	-
15	PNM	1,497	103
16	SRP	4,086	86
17	SDGE	3,055	439
18	SCE	18,237	-
19	SCPPA	739	-
20	TOUA	-	-
21	TSGT	1,256	222
22	TEP	1,948	134
23	USLC	547	-
24	USUC	-	-
25	USUC	-	-
26	WALC	457	572
27	WAUC	1,807	616
28	WED	-	-
29	WMS	-	-
30	**SUB TOTAL (5 + ... + 29)**	54,804	4,691
31	**TOTAL (4 + 30)**	58,747	4,691
	APS' SHARE OF TOTAL TARGET MARKET		
32	**BEFORE OPEN-ACCESS TARIFF (2 / 4)**	**100.0%**	**0.0%**
33	**AFTER OPEN-ACCESS TARIFF (2 / 31)**	**6.7%**	**0.0%**

TABLE 2

MARKET 5 OF 22

ANALYSIS OF EACH FIRST-TIER TARGET MARKET

LINE		TOTAL INSTALLED CAPACITY	UNCOMMITTED CAPACITY
1	**FIRST-TIER ENTITY: IID**	653	330
	BEFORE OPEN ACCESS TRANSMISSION TARIFF (DIRECTLY INTERCONNECTED ENTITIES)		
2	APS	3,943	-
3	EPE	1,486	63
4	PNM	1,497	103
5	SRP	4,086	86
6	USLC	547	-
7	WALC	457	572
8	SCE	18,237	-
9	LDWP	7,516	1,531
10	SDGE	3,055	439
11	SCPPA	739	-
12	**SUB TOTAL (2 + ... + 11)**	41,562	2,793
13	**TOTAL (1 + 12)**	42,215	3,123
	AFTER OPEN ACCESS TRANSMISSION TARIFF (ADDITIONAL POTENTIAL MARKET PARTICIPANTS)		
14	AEPC	520	38
15	CRIIP	-	-
16	ED/ID	-	-
17	NTUA	-	-
18	NEVP	2,994	-
19	PAC-W	6,833	-
20	PAC-E	938	558
21	PEGT	235	-
22	TOUA	-	-
23	TSGT	1,256	222
24	TEP	1,948	134
25	USUC	-	-
26	USUC	-	-
27	WAUC	1,807	616
28	WED	-	-
29	WMS	-	-
30	**SUB TOTAL (14 + ... + 29)**	16,531	1,568
31	**TOTAL (13 + 30)**	58,747	4,691
	APS' SHARE OF TOTAL TARGET MARKET		
32	**BEFORE OPEN-ACCESS TARIFF (2 / 13)**	**9.3%**	**0.0%**
33	**AFTER OPEN-ACCESS TARIFF (2 / 31)**	**6.7%**	**0.0%**

TABLE 2

MARKET 6 OF 22

ANALYSIS OF EACH FIRST-TIER TARGET MARKET

LINE		TOTAL INSTALLED CAPACITY	UNCOMMITTED CAPACITY
1	**FIRST-TIER ENTITY: LDWP**	7,516	1,531
	BEFORE OPEN ACCESS TRANSMISSION TARIFF (DIRECTLY INTERCONNECTED ENTITIES)		
2	APS	3,943	-
3	BPA	1,351	-
4	USCE	14,450	14,450
5	USPN	7,107	7,107
6	WAMP	45	45
7	ICPA	338	338
8	EPE	1,486	63
9	PNM	1,497	103
10	APA	400	23
11	SRP	4,086	86
12	USLC	547	-
13	TEP	1,948	134
14	IID	653	330
15	WALC	457	572
16	SCE	18,237	-
17	SDGE	3,055	439
18	NEVP	2,994	-
19	SCPPA	739	-
20	MWD	154	-
21	CDWR	1,838	1,027
22	ANHM	377	473
23	BURB	354	105
24	GLEN	345	72
25	PASA	327	66
26	RVSD	172	237
27	AZSA	32	62
28	BNNG	22	36
29	CLTN	2	33
30	VERN	43	83
31	PG&E	17,414	-
32	USMP	1,257	205
33	WAMP	1	961
34	MSR	143	143
35	**SUB TOTAL (2 + ... + 34)**	85,814	27,192
36	**TOTAL (1 + 35)**	93,330	28,723

TABLE 2

MARKET 6 OF 22

ANALYSIS OF EACH FIRST-TIER TARGET MARKET

LINE		TOTAL INSTALLED CAPACITY	UNCOMMITTED CAPACITY
	AFTER OPEN ACCESS TRANSMISSION TARIFF (ADDITIONAL POTENTIAL MARKET PARTICIPANTS)		
37	AEPC	520	38
38	CRIIP	-	-
39	ED/ID	-	-
40	NTUA	-	-
41	PAC-W	6,833	-
42	PAC-E	938	558
43	PEGT	235	-
44	TOUA	-	-
45	TSGT	1,256	222
46	USUC	-	-
47	USUC	-	-
48	WAUC	1,807	616
49	WED	-	-
50	WMS	-	-
51	**SUB TOTAL (37 + ... + 50)**	11,589	1,434
52	**TOTAL (36 + 51)**	104,919	30,157
	APS' SHARE OF TOTAL TARGET MARKET		
53	**BEFORE OPEN-ACCESS TARIFF (2 / 36)**	**4.2%**	**0.0%**
54	**AFTER OPEN-ACCESS TARIFF (2 / 52)**	**3.8%**	**0.0%**

TABLE 2

MARKET 7 OF 22

ANALYSIS OF EACH FIRST-TIER TARGET MARKET

LINE		TOTAL INSTALLED CAPACITY	UNCOMMITTED CAPACITY
1	NTUA	-	-
	BEFORE OPEN ACCESS TRANSMISSION TARIFF (DIRECTLY INTERCONNECTED ENTITIES)		
2	APS	3,943	-
3	PAC-W	6,833	-
4	PAC-E	938	558
5	USUC	-	-
6	USUC	-	-
7	TSGT	1,256	222
8	WAUC	1,807	616
9	EPE	1,486	63
10	NAPI	-	-
11	PNM	1,497	103
12	FARM	125	27
13	SRP	4,086	86
14	SCE	18,237	-
15	**SUB TOTAL (2 + ... + 14)**	40,208	1,675
16	**TOTAL (1 + 15)**	40,208	1,675
	AFTER OPEN ACCESS TRANSMISSION TARIFF (ADDITIONAL POTENTIAL MARKET PARTICIPANTS)		
17	AEPC	520	38
18	CRIIP	-	-
19	ED/ID	-	-
20	IID	653	330
21	LDWP	7,516	1,531
22	NEVP	2,994	-
23	PEGT	235	-
24	SDGE	3,055	439
25	SCPPA	739	-
26	TOUA	-	-
27	TEP	1,948	134
28	USLC	547	-
29	WALC	457	572
30	WED	-	-
31	WMS	-	-
32	**SUB TOTAL (17 + ... + 31)**	18,664	3,043
33	**TOTAL (16 + 32)**	58,872	4,718
	APS' SHARE OF TOTAL TARGET MARKET		
34	**BEFORE OPEN-ACCESS TARIFF (2 / 16)**	**9.8%**	**0.0%**
35	**AFTER OPEN-ACCESS TARIFF (2 / 33)**	**6.7%**	**0.0%**

TABLE 2

MARKET 8 OF 22

ANALYSIS OF EACH FIRST-TIER TARGET MARKET

LINE		TOTAL INSTALLED CAPACITY	UNCOMMITTED CAPACITY
1	**NEVP**	2,994	-
	BEFORE OPEN ACCESS TRANSMISSION TARIFF (DIRECTLY INTERCONNECTED ENTITIES)		
2	APS	3,943	-
3	PAC-W	6,833	-
4	PAC-E	938	558
5	USUC	-	-
6	USUC	-	-
7	WAUC	1,807	616
8	APA	400	23
9	SRP	4,086	86
10	USLC	547	-
11	TEP	1,948	134
12	WALC	457	572
13	SCE	18,237	-
14	LDWP	7,516	1,531
15	MWD	154	-
16	CDWR	1,838	1,027
17	**SUB TOTAL (2 + ... + 16)**	48,704	4,547
18	**TOTAL (1 + 17)**	51,698	4,547
	AFTER OPEN ACCESS TRANSMISSION TARIFF (ADDITIONAL POTENTIAL MARKET PARTICIPANTS)		
19	AEPC	520	38
20	CRIIP	-	-
21	EPE	1,486	63
22	ED/ID	-	-
23	IID	653	330
24	NTUA	-	-
25	PEGT	235	-
26	PNM	1,497	103
27	SDGE	3,055	439
28	SCPPA	739	-
29	TOUA	-	-
30	TSGT	1,256	222
31	WED	-	-
32	WMS	-	-
33	**SUB TOTAL (19 + ... + 32)**	9,441	1,195
34	**TOTAL (18 + 33)**	61,139	5,742
	APS' SHARE OF TOTAL TARGET MARKET		
35	**BEFORE OPEN-ACCESS TARIFF (2 / 18)**	**7.6%**	**0.0%**
36	**AFTER OPEN-ACCESS TARIFF (2 / 34)**	**6.4%**	**0.0%**

TABLE 2

MARKET 9 OF 22

ANALYSIS OF EACH FIRST-TIER TARGET MARKET

LINE		TOTAL INSTALLED CAPACITY	UNCOMMITTED CAPACITY
	PAC-W	6,833	-
	PAC-E	938	558
1	PAC	7,771	558
	BEFORE OPEN ACCESS TRANSMISSION TARIFF (DIRECTLY INTERCONNECTED ENTITIES)		
2	APS	3,943	-
3	BF	-	-
4	BPA	1,351	-
5	CC	-	-
6	CHPD	2,004	1,402
7	COPD	72	72
8	DOPD	840	665
9	EWEB	127	-
10	GCPD	1,967	1,452
11	GHPD	54	54
12	POPD	75	75
13	PGE	2,284	-
14	PSPL	2,545	-
15	SCL	1,904	-
16	TCL	879	-
17	WWPC	1,759	49
18	USCE	14,450	14,450
19	USPN	7,107	7,107
20	SHPD	212	212
21	WAMP	45	45
22	OKPD	-	-
23	IPC	2,646	-
24	MPC	1,585	-
25	UMPA	49	-
26	DGT	520	269
27	USUC	-	-
28	WAUM	-	-
29	SPP	1,118	-
30	UAMP	200	220
31	PSC	3,784	-
32	BEPC	651	149
33	USUC	-	-
34	PRPA	411	-
35	TSGT	1,256	222
36	BHPL	299	45
37	WALM	819	246
38	WAUC	1,807	616
39	WMPA	23	-
40	EPE	1,486	63
41	PNM	1,497	103
42	SRP	4,086	86
43	TEP	1,948	134
44	SCE	18,237	-
45	LDWP	7,516	1,531
46	NEVP	2,994	-
47	PG&E	17,414	-
48	USMP	1,257	205
49	WAMP	1	961
50	NCPA	404	-
51	USDI	-	-
52	TANC	-	-
53	SUB TOTAL (2 + ... + 52)	113,624	30,431
54	TOTAL (1 + 53)	120,457	30,989

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MARKET 9 OF 22

ANALYSIS OF EACH FIRST-TIER TARGET MARKET

LINE		TOTAL INSTALLED CAPACITY	UNCOMMITTED CAPACITY
	AFTER OPEN ACCESS TRANSMISSION TARIFF (ADDITIONAL POTENTIAL MARKET PARTICIPANTS)		
55	AEPC	520	38
56	CRIIP	-	-
57	ED/ID	-	-
58	IID	653	330
59	NTUA	-	-
60	PEGT	235	-
61	SDGE	3,055	439
62	SCPPA	739	-
63	TOUA	-	-
64	USLC	547	-
65	WALC	457	572
66	WED	-	-
67	WMS	-	-
68	SUB TOTAL (55 + ... + 67)	6,205	1,379
69	TOTAL (54 + 68)	126,663	32,368
	APS' SHARE OF TOTAL TARGET MARKET		
70	BEFORE OPEN-ACCESS TARIFF (2 / 54)	3.3%	0.0%
71	AFTER OPEN-ACCESS TARIFF (2 / 69)	3.1%	0.0%

TABLE 2

MARKET 10 OF 22

ANALYSIS OF EACH FIRST-TIER TARGET MARKET

LINE		TOTAL INSTALLED CAPACITY	UNCOMMITTED CAPACITY
1	PEGT	235	-
	BEFORE OPEN ACCESS TRANSMISSION TARIFF (DIRECTLY INTERCONNECTED ENTITIES)		
2	APS	3,943	-
3	USUC	-	-
4	USUC	-	-
5	TSGT	1,256	222
6	WAUC	1,807	616
7	EPE	1,486	63
8	PNM	1,497	103
9	SRP	4,086	86
10	TEP	1,948	134
11	**SUB TOTAL (2 + ... + 10)**	16,023	1,224
12	**TOTAL (1 + 11)**	16,258	1,224
	AFTER OPEN ACCESS TRANSMISSION TARIFF (ADDITIONAL POTENTIAL MARKET PARTICIPANTS)		
13	AEPC	520	38
14	CRIP	-	-
15	ED/ID	-	-
16	IID	653	330
17	LDWP	7,516	1,531
18	NTUA	-	-
19	NEVP	2,994	-
20	PAC-W	6,833	-
21	PAC-E	938	558
22	SDGE	3,055	439
23	SCE	18,237	-
24	SCPPA	739	-
25	TOUA	-	-
26	USLC	547	-
27	WALC	457	572
28	WED	-	-
29	WMS	-	-
30	**SUB TOTAL (13 + ... + 29)**	42,488	3,467
31	**TOTAL (12 + 30)**	58,747	4,691
	APS' SHARE OF TOTAL TARGET MARKET		
32	**BEFORE OPEN-ACCESS TARIFF (2 / 12)**	**24.3%**	**0.0%**
33	**AFTER OPEN-ACCESS TARIFF (2 / 31)**	**6.7%**	**0.0%**

TABLE 2

MARKET 11 OF 22

ANALYSIS OF EACH FIRST-TIER TARGET MARKET

LINE		TOTAL INSTALLED CAPACITY	UNCOMMITTED CAPACITY
1	**FIRST-TIER ENTITY: PNM**	1,497	103
	BEFORE OPEN ACCESS TRANSMISSION TARIFF (DIRECTLY INTERCONNECTED ENTITIES)		
2	APS	3,943	-
3	PAC-W	6,833	-
4	PAC-E	938	558
5	USUC	-	-
6	UAMP	200	220
7	PSC	3,784	-
8	USUC	-	-
9	TSGT	1,256	222
10	WAUC	1,807	616
11	EPE	1,486	63
12	PEGT	235	-
13	NAPI	-	-
14	LAC	89	31
15	FARM	125	27
16	TNP	-	-
17	HOW	-	-
18	SRP	4,086	86
19	TEP	1,948	134
20	AEPC	520	38
21	NTUA	-	-
22	SCE	18,237	-
23	LDWP	7,516	1,531
24	SDGE	3,055	439
25	SCPPA	739	-
26	ANHM	377	473
27	MSR	143	143
28	**SUB TOTAL (2 + ... + 27)**	57,317	4,580
29	**TOTAL (1 + 28)**	58,813	4,683
	AFTER OPEN ACCESS TRANSMISSION TARIFF (ADDITIONAL POTENTIAL MARKET PARTICIPANTS)		
30	CRIP	-	-
31	ED/ID	-	-
32	HD	653	330
33	NEVP	2,994	-
34	TOUA	-	-
35	USLC	547	-
36	WALC	457	572
37	WED	-	-
38	WMS	-	-
39	**SUB TOTAL (29 + ... + 38)**	4,651	901
40	**TOTAL (29 + 39)**	63,464	5,585
	APS' SHARE OF TOTAL TARGET MARKET		
41	**BEFORE OPEN-ACCESS TARIFF (2 / 29)**	**6.7%**	**0.0%**
42	**AFTER OPEN-ACCESS TARIFF (2 / 40)**	**6.2%**	**0.0%**

TABLE 2

MARKET 12 OF 22

ANALYSIS OF EACH FIRST-TIER TARGET MARKET

LINE		TOTAL INSTALLED CAPACITY	UNCOMMITTED CAPACITY
1	**FIRST-TIER ENTITY: SRP**	4,086	86
	BEFORE OPEN ACCESS TRANSMISSION TARIFF (DIRECTLY INTERCONNECTED ENTITIES)		
2	APS	3,943	-
3	PAC-W	6,833	-
4	PAC-E	938	558
5	USUC	-	-
6	PSC	3,784	-
7	USUC	-	-
8	PRPA	411	-
9	TSGT	1,256	222
10	WAUC	1,807	616
11	EPE	1,486	63
12	PEGT	235	-
13	PNM	1,497	103
14	USLC	547	-
15	TEP	1,948	134
16	IID	653	330
17	AEPC	520	38
18	WALC	457	572
19	SCE	18,237	-
20	LDWP	7,516	1,531
21	SDGE	3,055	439
22	NEVP	2,994	-
23	SCPPA	739	-
24	MWD	154	-
25	**SUB TOTAL (2 + ... + 24)**	59,009	4,605
26	**TOTAL (1 + 25)**	63,095	4,691
	AFTER OPEN ACCESS TRANSMISSION TARIFF (ADDITIONAL POTENTIAL MARKET PARTICIPANTS)		
27	CRIIP	-	-
28	ED/ID	-	-
29	NTUA	-	-
30	TOUA	-	-
31	WED	-	-
32	WMS	-	-
33	**SUB TOTAL (26 + ... + 32)**	-	-
34	**TOTAL (26 + 33)**	63,095	4,691
	APS' SHARE OF TOTAL TARGET MARKET		
35	**BEFORE OPEN-ACCESS TARIFF (2 / 26)**	**6.2%**	**0.0%**
36	**BEFORE OPEN-ACCESS TARIFF (2 / 34)**	**6.2%**	**0.0%**

TABLE 2

MARKET 13 OF 22

ANALYSIS OF EACH FIRST-TIER TARGET MARKET

LINE		TOTAL INSTALLED CAPACITY	UNCOMMITTED CAPACITY
1	**FIRST-TIER ENTITY: SDGE**	3,055	439
	BEFORE OPEN ACCESS TRANSMISSION TARIFF (DIRECTLY INTERCONNECTED ENTITIES)		
2	APS	3,943	-
3	EPE	1,486	63
4	PNM	1,497	103
5	SRP	4,086	86
6	IID	653	330
7	SCE	18,237	-
8	LDWP	7,516	1,531
9	SCPPA	739	-
10	ANHM	377	473
11	RVSD	172	237
12	CFE	1,330	220
13	**SUB TOTAL (2 + ... + 12)**	40,036	3,042
14	**TOTAL (1 + 13)**	43,091	3,481
	AFTER OPEN ACCESS TRANSMISSION TARIFF (ADDITIONAL POTENTIAL MARKET PARTICIPANTS)		
15	AEPC	520	38
16	CRIIP	-	-
17	ED/ID	-	-
18	NTUA	-	-
19	NEVP	2,994	-
20	PAC-W	6,833	-
21	PAC-E	938	558
22	PEGT	235	-
23	TOUA	-	-
24	TSGT	1,256	222
25	TEP	1,948	134
26	USLC	547	-
27	USUC	-	-
28	USUC	-	-
29	WALC	457	572
30	WAUC	1,807	616
31	WED	-	-
32	WMS	-	-
33	**SUB TOTAL (15 + ... + 32)**	17,535	2,140
34	**TOTAL (14 + 33)**	60,626	5,621
	APS' SHARE OF TOTAL TARGET MARKET		
35	**BEFORE OPEN-ACCESS TARIFF (2 / 14)**	**9.2%**	**0.0%**
36	**AFTER OPEN-ACCESS TARIFF (2 / 34)**	**6.5%**	**0.0%**

TABLE 2

MARKET 14 OF 22

ANALYSIS OF EACH FIRST-TIER TARGET MARKET

LINE		TOTAL INSTALLED CAPACITY	UNCOMMITTED CAPACITY
	AFTER OPEN ACCESS TRANSMISSION TARIFF (ADDITIONAL POTENTIAL MARKET PARTICIPANTS)		
45	AEPC	520	100
46	CRIIP	-	-
47	ED/ID	-	-
48	NTUA	-	-
49	PEGT	235	-
50	TOUA	-	-
51	WED	-	-
52	WMS	-	-
53	**SUB TOTAL (45 + ... + 52)**	755	100
54	**TOTAL (44 + 53)**	84,121	8,604
	APS' SHARE OF TOTAL TARGET MARKET		
55	**BEFORE OPEN-ACCESS TARIFF (2 / 44)**	**4.7%**	**0.0%**
56	**BEFORE OPEN-ACCESS TARIFF (2 / 54)**	**4.7%**	**0.0%**

TABLE 2

MARKET 15 OF 22

ANALYSIS OF EACH FIRST-TIER TARGET MARKET

LINE		TOTAL INSTALLED CAPACITY	UNCOMMITTED CAPACITY
1	SCPPA	739	-
	BEFORE OPEN ACCESS TRANSMISSION TARIFF (DIRECTLY INTERCONNECTED ENTITIES)		
2	APS	3,943	-
3	ICPA	338	338
4	USUC	-	-
5	UAMP	200	220
6	PSC	3,784	-
7	USUC	-	-
8	TSGT	1,256	222
9	WAUC	1,807	616
10	EPE	1,486	63
11	PEGT	235	-
12	NAPI	-	-
13	PNM	1,497	103
14	LAC	89	31
15	FARM	125	27
16	SRP	4,086	86
17	IID	653	330
18	SCE	18,237	-
19	LDWP	7,516	1,531
20	SDGE	3,055	439
21	BURB	354	105
22	GLEN	345	72
23	PASA	327	66
24	RVSD	172	237
25	AZSA	32	62
26	BNNG	22	36
27	CLTN	2	33
28	VERN	43	83
29	MSR	143	143
30	**SUB TOTAL (2 + ... + 29)**	49,747	4,841
31	**TOTAL (1 + 30)**	50,486	4,841

TABLE 2

MARKET 15 OF 22

ANALYSIS OF EACH FIRST-TIER TARGET MARKET

LINE		TOTAL INSTALLED CAPACITY	UNCOMMITTED CAPACITY
	AFTER OPEN ACCESS TRANSMISSION TARIFF (ADDITIONAL POTENTIAL MARKET PARTICIPANTS)		
32	AEPC	520	38
33	CRIIP	-	-
34	ED/ID	-	-
35	NTUA	-	-
36	NEVP	2,994	-
37	PAC-W	6,833	-
38	PAC-E	938	558
39	TOUA	-	-
40	TEP	1,948	134
41	USLC	547	-
42	WALC	457	572
43	WED	-	-
44	WMS	-	-
45	**SUB TOTAL (32 + ... + 44)**	14,237	1,302
46	**TOTAL (31 + 45)**	64,723	6,143
	APS' SHARE OF TOTAL TARGET MARKET		
47	**BEFORE OPEN-ACCESS TARIFF (2 / 31)**	**7.8%**	**0.0%**
48	**AFTER OPEN-ACCESS TARIFF (2 / 46)**	**6.1%**	**0.0%**

TABLE 2

MARKET 16 OF 22

ANALYSIS OF EACH FIRST-TIER TARGET MARKET

LINE		TOTAL INSTALLED CAPACITY	UNCOMMITTED CAPACITY
1	TOUA	-	-
	BEFORE OPEN ACCESS TRANSMISSION TARIFF (DIRECTLY INTERCONNECTED ENTITIES)		
2	APS	3,943	-
3	**SUB TOTAL (2 + ... + 2)**	3,943	-
4	**TOTAL (1 + 3)**	3,943	-
	AFTER OPEN ACCESS TRANSMISSION TARIFF (ADDITIONAL POTENTIAL MARKET PARTICIPANTS)		
5	AEPC	520	38
6	CRIIP	-	-
7	EPE	1,486	63
8	ED/ID	-	-
9	IID	653	330
10	LDWP	7,516	1,531
11	NTUA	-	-
12	NEVP	2,994	-
13	PAC-W	6,833	-
14	PAC-E	938	558
15	PEGT	235	-
16	PNM	1,497	103
17	SRP	4,086	86
18	SDGE	3,055	439
19	SCE	18,237	-
20	SCPPA	739	-
21	TSGT	1,256	222
22	TEP	1,948	134
23	USLC	547	-
24	USUC	-	-
25	USUC	-	-
26	WALC	457	572
27	WAUC	1,807	616
28	WED	-	-
29	WMS	-	-
30	**SUB TOTAL (5 + ... + 29)**	54,804	4,691
31	**TOTAL (4 + 30)**	58,747	4,691
	APS' SHARE OF TOTAL TARGET MARKET		
32	**BEFORE OPEN-ACCESS TARIFF (2 / 4)**	**100.0%**	**0.0%**
33	**AFTER OPEN-ACCESS TARIFF (2 / 31)**	**6.7%**	**0.0%**

TABLE 2

MARKET 17 OF 22

ANALYSIS OF EACH FIRST-TIER TARGET MARKET

LINE		TOTAL INSTALLED CAPACITY	UNCOMMITTED CAPACITY
1	TSGT	1,256	222
	BEFORE OPEN ACCESS TRANSMISSION TARIFF (DIRECTLY INTERCONNECTED ENTITIES)		
2	APS	3,943	-
3	PAC-W	6,833	-
4	PAC-E	938	558
5	DGT	520	269
6	USUC	-	-
7	UAMP	200	220
8	WPE	81	-
9	CSU	536	11
10	ARPA	75	46
11	PSC	3,784	-
12	BEPC	651	149
13	USUC	-	-
14	PRPA	411	-
15	BHPL	299	45
16	WALM	819	246
17	WAUC	1,807	616
18	RMGC	-	-
19	MEAN	38	-
20	WMPA	23	-
21	EPE	1,486	63
22	PEGT	235	-
23	NAPI	-	-
24	PNM	1,497	103
25	LAC	89	31
26	FARM	125	27
27	SRP	4,086	86
28	TEP	1,948	134
29	SCE	18,237	-
30	SCPPA	739	-
31	ANHM	377	473
32	MSR	143	143
33	NPPD	-	-
34	BEPC	-	-
35	SWPS	-	-
36	SUB TOTAL (2 + ... + 35)	49,920	3,220
37	TOTAL (1 + 36)	51,176	3,443

TABLE 2

MARKET 17 OF 22

ANALYSIS OF EACH FIRST-TIER TARGET MARKET

LINE		TOTAL INSTALLED CAPACITY	UNCOMMITTED CAPACITY
	AFTER OPEN ACCESS TRANSMISSION TARIFF (ADDITIONAL POTENTIAL MARKET PARTICIPANTS)		
38	AEPC	520	38
39	CRIIP	-	-
40	ED/ID	-	-
41	IID	653	330
42	LDWP	7,516	1,531
43	NTUA	-	-
44	NEVP	2,994	-
45	SDGE	3,055	439
46	TOUA	-	-
47	USLC	547	-
48	WALC	457	572
49	WED	-	-
50	WMS	-	-
51	**SUB TOTAL (38 + ... + 50)**	15,742	2,909
52	**TOTAL (37 + 51)**	66,917	6,352
	APS' SHARE OF TOTAL TARGET MARKET		
53	**BEFORE OPEN-ACCESS TARIFF (2 / 37)**	**7.7%**	**0.0%**
54	**AFTER OPEN-ACCESS TARIFF (2 / 52)**	**5.9%**	**0.0%**

TABLE 2

MARKET 18 OF 22

ANALYSIS OF EACH FIRST-TIER TARGET MARKET

LINE		TOTAL INSTALLED CAPACITY	UNCOMMITTED CAPACITY
1	**FIRST-TIER ENTITY: TEP**	1,948	134
	BEFORE OPEN ACCESS TRANSMISSION TARIFF (DIRECTLY INTERCONNECTED ENTITIES)		
2	APS	3,943	-
3	PAC-W	6,833	-
4	PAC-E	938	558
5	USUC	-	-
6	UAMP	200	220
7	PSC	3,784	-
8	USUC	-	-
9	TSGT	1,256	222
10	WAUC	1,807	616
11	EPE	1,486	63
12	PEGT	235	-
13	NAPI	-	-
14	PNM	1,497	103
15	LAC	89	31
16	FARM	125	27
17	TNP	-	-
18	SRP	4,086	86
19	USLC	547	-
20	AEPC	520	38
21	WALC	457	572
22	CPC	-	-
23	SCE	18,237	-
24	LDWP	7,516	1,531
25	SDGE	3,055	439
26	NEVP	2,994	-
27	SCPPA	739	-
28	ANHM	377	473
29	MSR	143	143
30	**SUB TOTAL (2 + ... + 29)**	60,863	5,121
31	**TOTAL (1 + 30)**	62,811	5,255
	AFTER OPEN ACCESS TRANSMISSION TARIFF (ADDITIONAL POTENTIAL MARKET PARTICIPANTS)		
32	CRIIP	-	-
33	ED/ID	-	-
34	IID	653	330
35	NTUA	-	-
36	TOUA	-	-
37	WED	-	-
38	WMS	-	-
39	**SUB TOTAL (31 + ... + 38)**	653	330
40	**TOTAL (31 + 39)**	63,464	5,585
	APS' SHARE OF TOTAL TARGET MARKET		
41	**BEFORE OPEN-ACCESS TARIFF (2 / 31)**	**6.3%**	**0.0%**
42	**AFTER OPEN-ACCESS TARIFF (2 / 40)**	**6.2%**	**0.0%**

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MARKET 19 OF 22

ANALYSIS OF EACH FIRST-TIER TARGET MARKET

LINE		TOTAL INSTALLED CAPACITY	UNCOMMITTED CAPACITY
	WALC	457	572
	USLC	547	-
1	WALC	1,004	572
	BEFORE OPEN ACCESS TRANSMISSION TARIFF (DIRECTLY INTERCONNECTED ENTITIES)		
2	APS	3,943	-
3	USUC	-	-
4	USUC	-	-
5	WAUC	1,807	616
6	APA	400	23
7	SRP	4,086	86
8	TEP	1,948	134
9	IID	653	330
10	CUC	45	7
11	AEPC	520	38
12	YID	-	-
13	SCE	18,237	-
14	LDWP	7,516	1,531
15	NEVP	2,994	-
16	MWD	154	-
17	**SUB TOTAL (2 + ... + 16)**	42,304	2,764
18	**TOTAL (1 + 17)**	42,761	3,336
	AFTER OPEN ACCESS TRANSMISSION TARIFF (ADDITIONAL POTENTIAL MARKET PARTICIPANTS)		
19	CRIIP	-	-
20	EPE	1,486	63
21	ED/ID	-	-
22	NTUA	-	-
23	PAC-W	6,833	-
24	PAC-E	938	558
25	PEGT	235	-
26	PNM	1,497	103
27	SDGE	3,055	439
28	SCPPA	739	-
29	TOUA	-	-
30	TSGT	1,256	222
31	WED	-	-
32	WMS	-	-
33	**SUB TOTAL (18 + ... + 32)**	16,039	1,385
34	**TOTAL (18 + 33)**	58,799	4,721
	APS' SHARE OF TOTAL TARGET MARKET		
35	**BEFORE OPEN-ACCESS TARIFF (2 / 18)**	**9.2%**	**0.0%**
36	**AFTER OPEN-ACCESS TARIFF (2 / 34)**	**6.7%**	**0.0%**

TABLE 2

MARKET 20 OF 22

ANALYSIS OF EACH FIRST-TIER TARGET MARKET

LINE		TOTAL INSTALLED CAPACITY	UNCOMMITTED CAPACITY
	WAUC	1,807	616
	USUC	-	-
	USUC	-	-
1	WAUC	1,807	616
	BEFORE OPEN ACCESS TRANSMISSION TARIFF (DIRECTLY INTERCONNECTED ENTITIES)		
2	APS	3,943	-
3	PAC-W	6,833	-
4	PAC-E	938	558
5	DGT	520	269
6	UAMP	200	220
7	WPE	81	-
8	CSU	536	11
9	PSC	3,784	-
10	BEPC	651	149
11	PRPA	411	-
12	TSGT	1,256	222
13	BHPL	299	45
14	WALM	819	246
15	RMGC	-	-
16	WMPA	23	-
17	EPE	1,486	63
18	PEGT	235	-
19	NAPI	-	-
20	PNM	1,497	103
21	LAC	89	31
22	SRP	4,086	86
23	USLC	547	-
24	TEP	1,948	134
25	NTUA	-	-
26	WALC	457	572
27	SCE	18,237	-
28	NEVP	2,994	-
29	SCPPA	739	-
30	ANHM	377	473
31	PG&E	17,414	-
32	USMP	1,257	205
33	WAMP	1	961
34	NCPA	404	-
35	MSR	143	143
36	USDI	-	-
37	TANC	-	-
38	**SUB TOTAL (2 + ... + 37)**	72,205	4,491
39	**TOTAL (1 + 38)**	74,012	5,107

TABLE 2

MARKET 20 OF 22

ANALYSIS OF EACH FIRST-TIER TARGET MARKET

LINE		TOTAL INSTALLED CAPACITY	UNCOMMITTED CAPACITY
	AFTER OPEN ACCESS TRANSMISSION TARIFF (ADDITIONAL POTENTIAL MARKET PARTICIPANTS)		
40	AEPC	520	38
41	CRIIP	-	-
42	ED/ID	-	-
43	IID	653	330
44	LDWP	7,516	1,531
45	SDGE	3,055	439
46	TOUA	-	-
47	WED	-	-
48	WMS	-	-
49	**SUB TOTAL (40 + ... + 48)**	11,744	2,337
50	**TOTAL (39 + 49)**	85,756	7,444
	APS' SHARE OF TOTAL TARGET MARKET		
51	**BEFORE OPEN-ACCESS TARIFF (2 / 39)**	**5.3%**	**0.0%**
52	**AFTER OPEN-ACCESS TARIFF (2 / 50)**	**4.6%**	**0.0%**

TABLE 2

MARKET 21 OF 22

ANALYSIS OF EACH FIRST-TIER TARGET MARKET

LINE		TOTAL INSTALLED CAPACITY	UNCOMMITTED CAPACITY
1	WED	-	-
	BEFORE OPEN ACCESS TRANSMISSION TARIFF (DIRECTLY INTERCONNECTED ENTITIES)		
2	APS	3,943	-
3	**SUB TOTAL (2 + ... + 2)**	3,943	-
4	**TOTAL (1 + 3)**	3,943	-
	AFTER OPEN ACCESS TRANSMISSION TARIFF (ADDITIONAL POTENTIAL MARKET PARTICIPANTS)		
5	AEPC	520	38
6	CRIIP	-	-
7	EPE	1,486	63
8	ED/ID	-	-
9	IID	653	330
10	LDWP	7,516	1,531
11	NTUA	-	-
12	NEVP	2,994	-
13	PAC-W	6,833	-
14	PAC-E	938	558
15	PEGT	235	-
16	PNM	1,497	103
17	SRP	4,086	86
18	SDGE	3,055	439
19	SCE	18,237	-
20	SCPPA	739	-
21	TOUA	-	-
22	TSGT	1,256	222
23	TEP	1,948	134
24	USLC	547	-
25	USUC	-	-
26	USUC	-	-
27	WALC	457	572
28	WAUC	1,807	616
29	WMS	-	-
30	**SUB TOTAL (5 + ... + 29)**	54,804	4,691
31	**TOTAL (4 + 30)**	58,747	4,691
	APS' SHARE OF TOTAL TARGET MARKET		
32	**BEFORE OPEN-ACCESS TARIFF (2 / 4)**	**100.0%**	**0.0%**
33	**AFTER OPEN-ACCESS TARIFF (1 / 31)**	**6.7%**	**0.0%**

TABLE 2

MARKET 22 OF 22

ANALYSIS OF EACH FIRST-TIER TARGET MARKET

LINE		TOTAL INSTALLED CAPACITY	UNCOMMITTED CAPACITY
1	WMS	-	-
	BEFORE OPEN ACCESS TRANSMISSION TARIFF (DIRECTLY INTERCONNECTED ENTITIES)		
2	APS	3,943	-
3	**SUB TOTAL (2 + ... + 2)**	3,943	-
4	**TOTAL (1 + 3)**	3,943	-
	AFTER OPEN ACCESS TRANSMISSION TARIFF (ADDITIONAL POTENTIAL MARKET PARTICIPANTS)		
5	AEPC	520	38
6	CRIIP	-	-
7	EPE	1,486	63
8	ED/ID	-	-
9	IID	653	330
10	LDWP	7,516	1,531
11	NTUA	-	-
12	NEVP	2,994	-
13	PAC-W	6,833	-
14	PAC-E	938	558
15	PEGT	235	-
16	PNM	1,497	103
17	SRP	4,086	86
18	SDGE	3,055	439
19	SCE	18,237	-
20	SCPPA	739	-
21	TOUA	-	-
22	TSGT	1,256	222
23	TEP	1,948	134
24	USLC	547	-
25	USUC	-	-
26	USUC	-	-
27	WALC	457	572
28	WAUC	1,807	616
29	WED	-	-
30	**SUB TOTAL (5 + ... + 29)**	54,804	4,691
31	**TOTAL (4 + 30)**	58,747	4,691
	APS' SHARE OF TOTAL TARGET MARKET		
32	**BEFORE OPEN-ACCESS TARIFF (2 / 4)**	**100.0%**	**0.0%**
33	**AFTER OPEN-ACCESS TARIFF (1 / 31)**	**6.7%**	**0.0%**

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TABLE 3

SUMMARY ANALYSIS
APS' MARKET SHARES OF TOTAL INSTALLED CAPACITY AND UNCOMMITTED CAPACITY

	INSTALLED CAPACITY		UNCOMMITTED CAPACITY	
Target Market	APS' Share Without Open Access Tariff	APS' Share With Open Access Tariff	APS' Share Without Open Access Tariff	APS' Share With Open Access Tariff
ARIZONA ELECTRIC PWR COOP INC	27%	7%	0%	0%
COLORADO RIVER INDIAN IRRIGATION PROJECT	80%	7%	0%	0%
EL PASO ELECTRIC CO.	7%	7%	0%	0%
ELECTRICAL and IRRIGATION DISTRICTS	100%	7%	0%	0%
IMPERIAL IRRIGATION DISTRICT	9%	7%	0%	0%
LOS ANGELES DEPT OF WATER & POWER	4%	4%	0%	0%
NAVAJO TRIBAL UTILITY AUTHORITY	10%	7%	0%	0%
NEVADA POWER CO.	8%	6%	0%	0%
PACIFICORP	3%	3%	0%	0%
PLAINS ELECTRIC GEN & TRANS COOP	24%	7%	0%	0%
PSC OF NEW MEXICO	7%	6%	0%	0%
SALT RIVER PROJECT	6%	6%	0%	0%
SAN DIEGO GAS & ELECTRIC CO.	9%	7%	0%	0%
SOUTHERN CALIFORNIA EDISON CO.	5%	5%	0%	0%
SOUTHERN CALIFORNIA PUBLIC POWER ASSOCIATION	8%	6%	0%	0%
TOHONO O'ODHAM UTILITY AUTHORITY	100%	7%	0%	0%
TRI-STATE G & T ASSN, INC.	8%	6%	0%	0%
TUCSON ELECTRIC POWER CO.	6%	6%	0%	0%
WESTERN AREA POWER ADMIN. -LOWER COLORADO RIVER	9%	7%	0%	0%
WESTERN AREA POWER ADMIN. -UPPER COLORADO RIVER	5%	5%	0%	0%
WICKENBURG ELECTRICAL DEPARTMENT	100%	7%	0%	0%
WILLIAMS	100%	7%	0%	0%

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79 FERC ¶ 61,022

UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

Before Commissioners: Elizabeth Anne Moler, Chair;
Vicky A. Bailey, James J. Hoecker,
William L. Massey, and Donald F. Santa, Jr.

Arizona Public Service Company) Docket No. ER97-1672-000

ORDER CONDITIONALLY ACCEPTING FOR FILING
PROPOSED MARKET-BASED RATES

(Issued April 11, 1997)

In this order, we conditionally accept for filing, without suspension or hearing, the proposed market-based power sales rates filed by Arizona Public Service Company (Arizona Public Service).

Background

On February 12, 1997, Arizona Public Service filed an application for authorization to sell electric capacity and energy at market-based rates.

Notice of Arizona Public Service's application was published in the Federal Register, 62 Fed. Reg. 10,551 (1997), with comments, protests, and motions to intervene due on or before March 14, 1997.

A timely motion to intervene raising no substantive issues was filed by the Salt River Project Agricultural Improvement and Power District (Salt River Project).

A timely motion to intervene and protest was filed by several wholesale customers of Arizona Public Service (Districts), in which they request the Commission to set the question of market power for hearing.

Arizona Public Service filed an answer to the Districts' request for hearing.

Discussion

Procedural Matter

Pursuant to Rule 214 of the Commission's Rules of Practice and Procedure, 18 C.F.R. § 385.214 (1996), the timely, unopposed

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motions to intervene of the Salt River Project and the Districts serve to make them parties this proceeding.

Market-Based Rates

The Commission allows power sales at market-based rates if the seller and its affiliates do not have, or have adequately mitigated, market power in generation and transmission and cannot erect other barriers to entry. In order to demonstrate the absence or mitigation of market power, a transmission-owning public utility must have on file with the Commission an open access tariff for the provision of comparable services. The Commission also considers whether there is evidence of affiliate abuse or reciprocal dealing. 1/

As we explain below, we find that, with Arizona Public Service's filing of an open access pro forma compliance tariff, 2/ Arizona Public Service's market-based rate application, as modified in certain respects, meets these standards. Accordingly, we will conditionally accept the proposed market-based rates for filing, to become effective on the date of this order, as requested by Arizona Public Service, subject to the condition that Arizona Public Service revise its power sales tariff as discussed below.

1. Generation Market Power

In support of its market-based rate application, Arizona Public Service has submitted a generation dominance analysis which indicates that its market share of installed and uncommitted capacity will not exceed levels that the Commission has found to be acceptable. 3/

1/ E.g., Progress Power Marketing, Inc., 76 FERC ¶ 61,155 at 61,919 (1996), reh'g pending; Northwest Power Marketing Company, L.L.C., 75 FERC ¶ 61,281 at 61,889 (1996); accord Heartland Energy Services, Inc., 68 FERC ¶ 61,223 at 62,060-63 (1994).

2/ See Promoting Wholesale Competition Through Open Access Non-discriminatory Transmission Services by Public Utilities and Recovery of Stranded Costs by Public Utilities and Transmitting Utilities, Order No. 888, 61 Fed. Reg. 21,540 (1996), FERC Stats. & Regs. ¶ 31,036 (1996), order on reh'g, Order No. 888-A, 62 Fed. Reg. 12,274 (1997), FERC Stats. & Regs. ¶ 31,048 (1997), reh'g pending.

3/ See, e.g., Southwestern Public Service Company, 72 FERC ¶ 61,208 at 61,966-67 (1995), reh'g pending; Louisville Gas & (continued...)

The Districts suggest there is an inconsistency between the Commission's decision in Order No. 888-A 4/ to continue to use the "hub-and-spoke" method of delineating relevant geographic markets for assessing generation market power when considering applications for market-based rate authorization, and language in the Commission's Merger Policy Statement 5/ indicating that the hub-and-spoke method has certain drawbacks in defining geographic markets. They further state that a proper delineation of geographic markets would likely show that Arizona Public Service has generation market power, and that various price and non-price transmission service conditions proposed by Arizona Public Service would enable Arizona Public Service to impose anticompetitive pricing for its generation.

We recently addressed this issue in Consolidated Edison of New York, Inc., 78 FERC ¶ 61,298 (1997). Here, as there, we conclude that it is neither necessary nor appropriate to change the market power screen that we traditionally have used to analyze market-based rate applications. 6/ While the general issue of a public utility's market power is raised in both the merger and market-based rate contexts, there are also significant differences in some of the specific issues raised in the two types of proceedings, in the nature of the activities for which approval is sought, and in the timing deadlines within which we must complete our initial analyses. The Districts have failed to address any of these differences.

As an initial matter, proposed mergers raise a fundamental market power issue not presented in market-based rates: the potential for increased market concentration owing to the loss of competitors that results from the Commission's approval of a utility merger. Moreover, the Commission in the merger context evaluates the likely competitive impacts of a corporate

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(...continued)
Electric Company, 62 FERC ¶ 61,016 at 61,146 (1993).

4/ Order No. 888-A at ____, mimeo at 39.

5/ Inquiry Concerning the Commission's Merger Policy under the Federal Power Act, Order No. 592, 61 Fed. Reg. 68,595 (1996), FERC Stats. & Regs. ¶ 31,044 (1996).

6/ Of course, as we stated in New York State Electric and Gas Corporation, et al., 78 FERC ¶ 61,309 (1997), while we will not require applicants to support their requests for market-based rates with a comprehensive market power analysis as described in the merger policy statement, we will consider such an analysis if they wish to file it as a substitute for our traditional hub-and-spoke analysis.

reorganization which, once consummated, cannot easily be undone, and for which it may be more difficult to remedy anticompetitive problems after-the-fact. 7/ Further, the Commission in the merger context does not have a statutory time constraint in which it must apply a competitive screen analysis and issue an initial order. Merger applications thus require the Commission to apply a more thorough competitive screen analysis.

In contrast, in the market-based rate context the Commission is not faced with the elimination of competitors and is not asked to approve an activity that involves structural corporate changes in the marketplace. Additionally, the Commission must, in the absence of a request for waiver of prior notice or a proposed effective date beyond 60 days from filing, take initial action on a completed market-based rate application within 60 days and of necessity must use a market screen analysis which it is capable of applying within that short time frame. There is also not a need for as extensive a screen analysis in the market rate context because of the Commission's ability to monitor and remedy market power abuses by utilities charging market-based rates. If the Commission approves market-based rates, it monitors behavior and market structure on a continuing basis through reporting and filing requirements and can promptly remedy market power abuses by revoking market-based rates or taking other remedial action at any time.

Finally, we emphasize that the issue here is the screening analysis that is used to initially evaluate these different types of applications. As we stated in Order No. 888 at 31,660, intervenors may raise specific evidence challenging any presumption implicit in the Commission's screen analysis of market-based rate proposals. Here, the Districts have provided no such evidence.

Accordingly, we find that Arizona Public Service meets the Commission's generation market power standard for market-based rates.

2. Transmission Market Power

When a public utility seeks authorization to charge market-based rates, the Commission has required the public utility to have an open access transmission tariff on file before granting such authorization. 8/ Arizona Public Service has filed an open access transmission tariff in Docket No. OA96-153-000. For this

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7/ See 16 U.S.C. § 824b(b) (1994).

8/ See, e.g., Order No. 888 at 31,656-57; accord Southern Company Services, Inc. 71 FERC ¶ 61,392 at 62,536 (1995).

reason, we find that Arizona Public Service meets the Commission's transmission market power standard for approval of market-based rates.

We are not persuaded by the Districts' arguments to the contrary. The Districts argue that Arizona Public Service's open access transmission tariff has not been shown to mitigate transmission market power because its open access rates and various other non-rate terms and conditions have been set for hearing and may be excessive or discriminatory, 9/ and because Arizona Public Service's revised tariff has not yet been approved by the Commission. 10/

We have explained that we will not delay the effectiveness of market-based rate authority or attach refund conditions to market-based power sales rates simply because the utility's cost-based transmission rates have been set for hearing. 11/ Moreover, in its order addressing the non-rate terms and conditions of Arizona Public Services's open access transmission tariff only one change was directed, and one matter set for hearing. 12/ Customers still are assured of access to Arizona Public Service's transmission system under the pro forma terms and conditions, and have the ability to bring to the Commission's attention any implementation issues that arise with respect to

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9/ See Long Sault Inc., et al., 76 FERC ¶ 61,313 (1996) (setting for hearing rate issues arising under open access pro forma tariff filings, including Arizona Public Services' in Docket No. OA96-153-000); Arizona Public Service Company, 78 FERC ¶ 61,083 (1997) (Arizona Public Service) (consolidating Docket Nos. OA96-153-000 and ER96-2401-000); American Electric Power Service Corporation, et al., 78 FERC ¶ 61,070 (1997) (AEP) (directing certain revisions to Arizona Public Services' compliance filing in Docket No. OA96-153-000).

10/ On February 27, 1997, Arizona Public Service filed a revised open access transmission tariff in response to the Commission's orders in Arizona Public Service and AEP.

11/ See, e.g., American Electric Power Service Corporation, et al., 72 FERC ¶ 61,287 (1995).

12/ 78 FERC at 61,263-64 (Arizona Public Service was directed to provide a better description of *the methods it uses* to compute available transmission capability. A hearing was established concerning whether Arizona Public Service's system impact study methodology should be revised).

their specific service requests. This is sufficient to find that Arizona Public Service has mitigated its transmission market power.

3. Other Barriers to Entry/Reciprocal Dealing/Affiliate Abuse

We are satisfied, given Arizona Public Service's explanation, that there are no barrier to entry, reciprocal dealing or affiliate abuse of concern here.

Unbundling of Rates

Order No. 888 at 31,654 provides that, as part of the functional unbundling of wholesale services, the prices for wholesale generation, transmission and ancillary services must be separately stated for sales under requirements or coordination contracts executed after July 9, 1996. Arizona Public Service's market-based power sales tariff does not state that Arizona Public Service will obtain transmission under its open access transmission tariff, nor does it address the circumstances under which transmission and ancillary service will be provided under Arizona Public Service's open access transmission tariff. Thus, the tariff does not address our unbundling requirements.

Accordingly, we will direct Arizona Public Service to revise its market-based power sales tariff to state explicitly that Arizona Public Service will obtain transmission under its open access tariff, and to state explicitly separate prices for generation, transmission and ancillary services. In addition, we will require Arizona Public Service to revise its market-based tariff to state that: (1) when transmission and ancillary services to effectuate power sales transactions under Arizona Public Service's market-based tariff are to be obtained by Arizona Public Service, Arizona Public Service must file a service agreement placing itself under its open access transmission tariff; and (2) when the customer itself is obtaining the transmission and ancillary services from Arizona Public Service, Arizona Public Service must file a service agreement placing the customer under its open access tariff. 13/

Since we are permitting Arizona Public Service to report prices for short-term market-based transactions (one year or less) in quarterly summaries, as discussed below, the separate prices for the unbundled services in such short-term transactions should be included in those quarterly summaries. For long-term transactions (longer than one year), the separate prices should

13/ See Public Service Electric & Gas Company, 78 FERC ¶ 61,119 (1997).

be included in the service agreements filed for specific transactions.

Reporting and Filing Requirements

We will direct Arizona Public Service to inform the Commission promptly of any change in status that would reflect a departure from the characteristics the Commission has relied upon in approving market-based pricing. These include, but are not limited to: (1) ownership of generation or transmission facilities or inputs to electric power production other than fuel supplies; or (2) affiliation with any entity not disclosed in the filing that owns generation or transmission facilities or inputs to electric power production, or affiliation with any entity that has a franchised service area. 14/ Alternatively, Arizona Public may report such changes with the updated market analysis it will be required to file every three years. 15/

Consistent with procedures we have adopted in other cases, Arizona Public Service may file umbrella agreements for short-term transactions (one year or less) within 30 days of the date of commencement of short-term service, to be followed by quarterly transaction summaries of specific sales. For long-term transactions (longer than one year), Arizona Public Service must submit the actual individual service agreement for each transaction within 30 days of the date of commencement of service. 16/

To ensure the clear identification of filings, and in order to facilitate the orderly maintenance of the Commission's files and public access to the documents, long-term transaction service agreements (over one year) should not be filed together with short-term transaction (one year or less) summaries.

Arizona Public Service has indicated that it may engage in risk management transactions, including, but not limited to, options, swaps and futures. Arizona Public Service is required to report, consistent with the filing procedures set forth above,

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14/ See, e.g., Morgan Stanley Capital Group, Inc., 69 FERC ¶ 61,175 at 61,695 (1994), order on reh'g, 72 FERC ¶ 61,082 (1995) (Morgan Stanley); InterCoast Power Marketing Company, 68 FERC ¶ 61,248 at 62,134, clarified, 68 FERC ¶ 61,324 (1994).

15/ We reserve the right to require such an analysis any time.

16/ See Southern Company Services, Inc., 75 FERC ¶ 61,130 at 61,444-45 (1996), order on clarification, 75 FERC ¶ 61,353 (1996).

only those risk management transactions that result in the actual delivery of electricity. 17/

The Commission orders:

(A) Arizona Public Service Company is hereby directed to revise its market-based power sales tariff, within 15 days of the date of issuance of this order, to reflect the revisions discussed in the body of this order.

(B) Arizona Public Service's market-based power sales tariff is hereby conditionally accepted for filing, to become effective on the date of this order, on condition that Arizona Public Service makes the compliance filing directed in Ordering Paragraph (A) above.

(C) Arizona Public Service is hereby directed to conform to the filing and reporting requirements specified in this order. The first quarterly report of transactions undertaken by Arizona Public Service under its market-based power sales tariff will be due within 30 days of the calendar quarter ending June 30, 1997.

(D) Arizona Public Service is hereby directed to file an updated market analysis within three years of the date of this order, and every three years thereafter.

(E) Arizona Public Service is hereby directed to inform the Commission promptly of any change in status that would reflect a departure from the characteristics the Commission has relied upon in approving market-based pricing. Alternatively, as discussed in the body of this order, Arizona Public Service may elect to report any such changes every three years with the updated market analysis filed pursuant to Ordering Paragraph (D) above. Arizona Public Service shall notify the Commission of which option it elects in its first quarterly report filed pursuant to Ordering Paragraph (C) above.

17/ See Morgan Stanley, 69 FERC at 61,696.

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1800 M Street, N.W.
Washington, D.C. 20036-5869
202-467-7000
Fax: 202-467-7176

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REGULATORY COMMISSION

Morgan, Lewis & Bockius LLP
COUNSELORS AT LAW

March 28, 2001

The Honorable David P. Boergers
Secretary
Federal Energy Regulatory Commission
888 First Street, N.E.
Washington, D.C. 20426

Re: Application of Pinnacle West Energy Corporation for Determination of Exempt Wholesale Generator Status, Docket No. EG01-163-000.

Dear Secretary Boergers:

Enclosed for filing are: (1) a check made payable to the Treasurer of the United States in the amount of $1310.00; and (2) an original and eighteen copies of the Application of Pinnacle West Energy Corporation for Determination of Exempt Wholesale Generator Status ("Application"). Please file stamp and return four copies of the Application for our records.

If you have any questions regarding the attached Application or check, please contact the undersigned.

Sincerely,

Andrea Weinstein

Andrea J. Weinstein
Morgan, Lewis & Bockius LLP
1800 M Street, N.W.
Washington, D.C. 20036-5869
Phone: 202-467-7332

Enclosures

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UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Pinnacle West Energy Corporation **Docket No. EG01-_____**

APPLICATION OF PINNACLE WEST ENERGY CORPORATION FOR DETERMINATION OF EXEMPT WHOLESALE GENERATOR STATUS

Pursuant to Section 32 of the Public Utility Holding Company Act ("PUHCA"), 15 U.S.C. § 79z-5a (1994), and Subchapter T, Part 365 of the regulations of the Federal Energy Regulatory Commission ("FERC" or "Commission"), 18 C.F.R. Part 365 (2000), Pinnacle West Energy Corporation ("PWE") hereby applies for a determination that it will be an exempt wholesale generator ("EWG") within the meaning of section 32(a)(1) of PUHCA.

I. COMMUNICATIONS

All communications regarding this Application should be sent to:

Karilee S. Ramaley
Pinnacle West Capital Corporation
400 North 5th Street
Mail Station 8695
Phoenix, AZ 85004
(602) 250-3626

John D. McGrane
Mary Ann K. Huntington
Andrea J. Weinstein
Morgan, Lewis & Bockius LLP
1800 M Street, N.W.
Washington, D.C. 20036
(202) 467-7000

II. INFORMATION ABOUT PINNACLE WEST ENERGY CORPORATION

PWE is a wholly-owned subsidiary of Pinnacle West Capital Corporation ("PNW"), a public-utility holding company exempt from the provisions of the Public Utility Holding Company Act of 1935 ("PUHCA"), except Section 9(a)(2) thereof, by virtue of Section 3(a)(1) of PUHCA. Arizona Public Service Company ("APS") is PNW's only existing public-utility company affiliate. PWE was created to serve as PNW's competitive generation affiliate, and

PNW, over time, will move substantially all of APS's generating assets to PWE, while retaining its transmission and distribution facilities within APS. On July 28, 2000, in Docket No. EC00-118-000, PNW, PWE and APS filed a joint application pursuant to section 203 of the Federal Power Act requesting authorization to separate APS's generation and wholesale marketing businesses from its transmission and distribution businesses. On November 24, 2000, the Commission authorized the transfer of APS's generation assets, and associated transmission plant (step-up transformers and generator leads), and existing generation operating agreements to PWE. *See Arizona Public Service Company, et al.*, 93 FERC ¶ 61,216 (2000). Earlier, on September 12, 2000, PWE filed an application pursuant to Section 9(a)(2) of PUHCA requesting approval from the Securities and Exchange Commission ("SEC") in connection with the reorganization and transfer of APS's generating assets to PWE since it will result in PWE becoming a public-utility company. This application is currently pending before the SEC.[1] In addition to the APS facilities being moved to PWE, PWE plans to establish separate EWG subsidiaries to develop, own and operate generating plants located outside of Arizona.

III. SWORN STATEMENT

In support of this application, appended hereto and made a part hereof is the affidavit of Ajoy K. Banerjee, Vice President, Generation Expansion, which affirms and verifies the following facts:

1. PWE will be engaged directly, or indirectly through one or more affiliates as defined in section 2(a)(11)(B) of PUHCA, and exclusively in the business of owning or operating, or both owning and operating, all or part of one or more eligible facilities and selling electric energy at wholesale.

[1] PWE intends to maintain its EWG status until the SEC authorizes it to become a public-utility company and at that time PWE will notify the Commission.

2. The eligible facilities ("Facilities") PWE plans to directly or indirectly own and/or operate are:

(a) a 100% interest in West Phoenix Unit No. 4 ("West Phoenix No. 4"), a newly constructed natural gas-fired, combined cycle unit with a nominal power output of 120 MW located on the site of APS's West Phoenix Plant;

(b) a 100% interest in 10 trailer-mounted generating units ("trailer-mounted units") with a combined capacity of less than 200 MW. Five of the trailer-mounted units will be located on the site of the West Phoenix Plant and five will be located on the site of the Saguaro Power Plant in Red Rock, Arizona.

3. PWE will lease the trailer-mounted units from General Electric Energy Rentals, Inc. and will operate the trailer-mounted units. During the term of the lease, PWE will have all of the rights and privileges associated with ownership of the trailer-mounted units. As the operator of the trailer-mounted units, PWE will manage, control, operate, and maintain the units, and sell the electric output associated with the trailer-mounted units. *See, e.g., TXU (No. 5) Pty Ltd.*, 92 FERC ¶ 61,170 (2000); *Kalaeloa Partners, LP*, 77 FERC ¶ 61,075 (1996).

4. West Phoenix No. 4 and the trailer-mounted units constitute "eligible facilities" as defined in Section 32(a)(2) of PUHCA, because they will be used for the generation of electric energy exclusively for sale at wholesale.

5. PWE will not engage in any retail sales.

6. PWE is an associate of APS, which is an electric utility company as defined by Section 2(a)(3) of PUHCA.

7. No portion of the Facilities will be owned or operated by an electric utility company that is an affiliate or associate company of PWE. However, because West Phoenix No.

4 is located near generating facilities owned and operated by APS and because it is economically efficient to have a single entity perform certain routine day-to-day services necessary to run both the utility-owned and EWG-owned facilities since they are in close geographic proximity, PWE and APS intend to enter into a Services Agreement pursuant to which APS will provide certain services to PWE. APS will be responsible for providing the services identified in the Services Agreement, primarily daily maintenance activities, but will not have full operating responsibility for West Phoenix No. 4. *See, e.g., Prior Notice and Filing Requirements Under Part II of the Federal Power Act*, 64 FERC ¶ 61,139, at 61,993-94 (1993); *Puget Sound Power & Light Company*, 64 FERC ¶ 61,335, at 63,428 (1993).[2] Because the Service Agreement will satisfy both FERC and SEC precedent, the Services Agreement should not affect the Commission's EWG determination.[3]

8. There are no lease arrangements involving the Facilities and any United States public-utility company or any affiliate or associate of any United States public-utility company. However, as noted above, PWE is leasing the trailer-mounted units from General Electric Energy Rentals, Inc.

---

[2] Under SEC precedent, APS also should be not be considered the "operator" of West Phoenix No. 4 since APS will not: (1) hold any interest in PWE or the West Phoenix No. 4; and (2) will not sell electricity, schedule electrical output, bill, collect revenues, schedule interruptions in the delivery of electricity, procure fuel supply, or modify the capacity requirements of the facilities. *See Kenetech Windpower, Inc.*, SEC No-Action Letter (April 15, 1994); *Colstrip Energy Limited Partnership*, SEC No-Action Letter (November 14, 1989). Moreover, the fee structure under which APS will be compensated will not be related to the revenue or income PWE receives, nor will it be directly related to the electrical output from the facilities.

[3] In any event, even if APS were somehow viewed as "operating" West Phoenix No. 4, the plain language of Section 32(d) of PUHCA, which bars ownership or operation of a "portion" of an eligible facility by an affiliated electric utility company, does not apply to the current proposal since PWE will own the *entire* unit and APS would be "operating" the *entire* unit. In other words, there is no intermingling of operation or ownership since neither of the functions will be apportioned between the EWG and the affiliated electric utility.

9. PWE also plans to engage in activities that the Commission has previously determined to be "incidental" to an EWG's primary business of owning and operating eligible facilities and selling electric energy at wholesale. These activities include:

(a) developing and purchasing other eligible facilities. *See, e.g., China Power Partners, L.P.*, 70 FERC ¶ 61,256 (1995); *Southern Electric Wholesale Generators, Inc.*, 66 FERC ¶ 61,264 (1994).

(b) wholesale marketing and brokering of electric energy that PWE has not generated. *See, e.g., Entergy Power Marketing Corp.*, 73 FERC ¶ 61,063 (1995); *CNG Power Services Corp.*, 71 FERC ¶ 61,378 (1995); *LG&E Power Marketing, Inc.*, 67 FERC ¶ 61,083 (1994).

(c) selling or reselling ancillary services and interconnected operations services at wholesale. *See, e.g., Phelps Dodge Energy Services,* 88 FERC ¶ 61,052 (1999);

(d) selling by-products of electric generation, such as steam, fly ash and bottom ash. *See, e.g., Erie Boulevard Hydropower, L.P.,* 87 FERC ¶ 61,378 (1999);

(e) selling excess natural gas supplies and reassigning excess capacity originally obtained to effect a specific wholesale sale of electric energy. *See, e.g., Selkirk Cogen Partners, L.P.*, 69 FERC ¶ 61,037 (1994);

(f) delivering fuel to third parties to generate electric power to be delivered by that third party to PWE for sale at wholesale. *See, e.g., CNG Power Services Corp.*, 71 FERC ¶ 61,378 (1995); *Southern Energy Marketing, Inc.*, 71 FERC ¶ 61,376 (1995); and

(g) entering into contracts for transmission capacity solely to the extent necessary to effect sales at wholesale of electricity generated by PWE or others. *See, e.g., CNG Power Services Corp.*, 71 FERC ¶ 61,026 (1995).

10. In addition to the incidental activities above, PWE plans to own directly or indirectly a natural gas storage facility. The natural gas storage facility is necessary for the operation of West Phoenix No. 4 and is incidental to PWE's primary business of owning and operating eligible facilities and selling electric energy at wholesale. *See Desarollo Pectacalco S. De R. L. De C.V.*, 67 FERC ¶ 61,070 at 61,199, *order on reh'g*, 67 FERC ¶ 61,403 (1994) (fuel storage facilities are not part of the eligible facility and such facilities are incidental to primary EWG business); *Compañia Hidroeléctrica Doña Julia S. De R.L.*, 85 FERC ¶ 61,336 (1998) (ownership of discharge and offshoot pipelines for other hydroelectric projects is incidental to primary EWG business).

IV. NOTICE OF APPLICATION AND SERVICE

Included with this application is a form of notice in paper and electronic formats suitable for publication in the *Federal Register*. A copy of this application has been served on the Securities and Exchange Commission and the Arizona Corporation Commission.

V. CONCLUSION

For the foregoing reasons, PWE respectfully requests the Commission to determine that PWE is an Exempt Wholesale Generator under Section 32(a)(1) of PUHCA.

Respectfully submitted,

John D. McGrane
Mary Ann K. Huntington
Andrea J. Weinstein
Morgan, Lewis & Bockius LLP
1800 M Street, N.W.
Washington, D.C. 20036
Tel: (202) 467-7622/7621

Attorneys for
Pinnacle West Energy Corporation

Dated: March 28, 2001

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Pinnacle West Energy Corporation **Docket No. EG01-_____**

APPLICATION OF PINNACLE WEST ENERGY CORPORATION FOR DETERMINATION OF EXEMPT WHOLESALE GENERATOR STATUS

AFFIDAVIT OF
AJOY K. BANERJEE

STATE OF ARIZONA)
)
COUNTY OF MARICOPA)

The undersigned, Ajoy K. Banerjee, being first duly sworn, attests that I am Vice President, Generation Expansion, of Pinnacle West Energy Corporation; that as such I am legally authorized to bind Pinnacle West Energy Corporation; that I have read the foregoing Application of Pinnacle West Energy Corporation for Determination of Exempt Wholesale Generator Status (the "Application") and know the contents thereof; and that the facts and representations set forth in the Application are true and correct to the best of my knowledge, information, and belief.

Name: Ajoy K. Banerjee
Title: Vice President, Generation Expansion

Subscribed and sworn to before me
this twenty-seventh day of March 2001.

Notary Public

OFFICIAL SEAL
SCHERRY BOYER
NOTARY PUBLIC - STATE OF ARIZONA
MARICOPA COUNTY
My Comm Expires Oct. 14, 2002

1800 M Street, N.W.
Washington, D.C. 20036-5869
202-467-7000
Fax: 202-467-7176

(202) 467-7332

FILED
OFFICE OF THE SECRETARY
01 APR 27 PM 1:13
FEDERAL ENERGY
REGULATORY COMMISSION

Morgan, Lewis
& Bockius LLP
COUNSELORS AT LAW

April 27, 2001

The Honorable David P. Boergers
Secretary
Federal Energy Regulatory Commission
888 First Street, N.E.
Washington, D.C. 20426

Re: Amended and Supplemental Application of Pinnacle West Energy Corporation for Determination of Exempt Wholesale Generator Status, Docket No. EG01-163-001.

Dear Secretary Boergers:

Enclosed for filing are an original and fourteen copies of an Amended and Supplemental Application of Pinnacle West Energy Corporation for Determination of Exempt Wholesale Generator Status. In accordance with the Commission's rules, attached is a Notice of Filing in hard copy and on diskette.

Please file stamp and return four copies of the Amended and Supplemental Application for our records.

If you have any questions regarding the Amended and Supplemental Application, please contact the undersigned.

Sincerely,

Andrea Weinstein

Andrea J. Weinstein
Attorney for
Pinnacle West Energy Corporation

Enclosures

cc: Jan Macpherson
Securities and Exchange Commission
Arizona Corporation Commission

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Pinnacle West Energy Corporation) **Docket No. EG01-163-001**

AMENDED AND SUPPLEMENTAL APPLICATION FOR DETERMINATION OF EXEMPT WHOLESALE GENERATOR STATUS

On March 28, 2001, Pinnacle West Energy Corporation ("PWE") filed an application with the Federal Energy Regulatory Commission ("FERC" or "Commission") requesting that the Commission issue an order determining that PWE is an exempt wholesale generator ("EWG") pursuant to Section 32(a)(1) of the Public Utility Holding Company Act, as amended, and Part 365 of the Commission's regulations. PWE submits this amended and supplemental application to modify the eligible facilities it plans to directly or indirectly own and/or operate and to provide the Commission with additional information concerning PWE's development activities.

On page 3 of the initial application, PWE states that PWE plans to directly or indirectly own and/or operate a "100% interest in 10 trailer-mounted generating units ('trailer-mounted units') with a combined capacity of less than 200 MW." At this time, PWE no longer intends to operate the trailer-mounted units as eligible facilities. Instead, West Phoenix No. 4 will be PWE's only eligible facility. In the event that PWE later decides to operate the trailer-mounted units as eligible facilities, PWE will file a separate application for EWG status to cover those facilities.

In addition, on page 2 of the initial application, PWE states that "PWE plans to establish separate EWG subsidiaries to develop, own and operate generating plants located outside of Arizona." PWE wishes to clarify that prior to PWE's acquisition of any ownership interest or operation interest in any additional eligible facilities, PWE will either file for EWG status for such acquisition or notify the Commission pursuant to 18 C.F.R. § 365.8.

An applicant for an EWG determination is allowed to amend and supplement its application upon a showing of good cause, as allowed by 18 C.F.R. § 365.5, and PWE has demonstrated cause for amending and supplementing it application. This amended and supplemental application neither substantially alters PWE's initial application nor encompasses any activities not previously presented in that application.

PWE requests waiver of any applicable Commission regulations to the extent necessary to waive any applicable filing requirements. PWE provides in paper and electronic formats a proposed notice of filing suitable for publication in the Federal Register in the event the Commission elects to notice the filing.

In accordance with Section 365.5 of the Commission's regulations, 18 C.F.R. § 365.5, PWE is not required to submit an additional filing fee with this filing.

For the reasons set forth in PWE's initial application and this amended and supplemental application, PWE respectfully requests that the Commission determine that PWE is an exempt wholesale generator under Section 32(a)(1) of PUHCA.

Respectfully submitted,

John D. McGrane
Mary Ann K. Huntington
Andrea J. Weinstein
Morgan, Lewis & Bockius LLP
1800 M Street, N.W.
Washington, D.C. 20036
Tel: (202) 467-7000

Karilee S. Ramaley
Pinnacle West Capital Corporation
400 North 5th Street
Mail Station 8695
Phoenix, AZ 85004
(602) 250-3626

Attorneys for
Pinnacle West Energy Corporation

Dated: April 27, 2001

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Pinnacle West Energy Corporation **Docket No. EG01-163-001**

APPLICATION OF PINNACLE WEST ENERGY CORPORATION FOR DETERMINATION OF EXEMPT WHOLESALE GENERATOR STATUS

AFFIDAVIT OF
AJOY K. BANERJEE

STATE OF ARIZONA)
)
COUNTY OF MARICOPA)

The undersigned, Ajoy K. Banerjee, being first duly sworn, attests that I am Vice President, Generation Expansion of Pinnacle West Energy Corporation; that as such I am legally authorized to bind Pinnacle West Energy Corporation; that I have read the foregoing Application of Pinnacle West Energy Corporation for Determination of Exempt Wholesale Generator Status (the "Application") and know the contents thereof; and that the facts and representations set forth in the Application are true and correct to the best of my knowledge, information, and belief.

Name: Ajoy K. Banerjee
Title: Vice President, Generation Expansion

Subscribed and sworn to before me
this sixth day of April 2001.

Notary Public

OFFICIAL SEAL
JOY L. HEINRICH
Notary Public - State of Arizona
MARICOPA COUNTY
My Comm. Expires Oct. 1, 200

1800 M Street, N.W.
Washington, D.C. 20036-5869
202-467-7000
Fax: 202-467-7176

FILED
OFFICE OF THE SECRETARY
01 MAY -2 PM 3:55
FEDERAL ENERGY REGULATORY COMMISSION

Morgan, Lewis & Bockius LLP
COUNSELORS AT LAW

Andrea J. Weinstein
(202) 467-7332
ajweinstein@morganlewis.com

May 2, 2001

Hon. David P. Boergers, Secretary
Federal Energy Regulatory Commission
888 First Street, N.E.
Washington, D.C. 20426

RE: Pinnacle West Energy Corporation
Docket No. EG01-163-000

Dear Mr. Boergers:

Pursuant to Rule 216 of the Rules of Practice and Procedure of the Federal Energy Regulatory Commission, 18 C.F.R. § 385.216, Pinnacle West Energy Corporation ("PWE") hereby files an original and fourteen (14) copies of a Notice of Withdrawal of its Application for Determination of Exempt Wholesale Generator Status. No parties have intervened or protested the PWE Application, so no party will be prejudiced or otherwise affected by PWE's withdrawal. PWE requests waiver of the provisions of 18 C.F.R. § 385.216 to allow the withdrawal to become effective as of the date of this filing.

Respectfully submitted,

Andrea Weinstein

Andrea J. Weinstein
Attorney for
Pinnacle West Energy Corporation

cc: Jan Macpherson
Securities and Exchange Commission
Arizona Corporation Commission

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Pinnacle West Energy Corporation) **Docket No. EG01-163-000**

NOTICE OF WITHDRAWAL

Pursuant to Rule 216 of the Rules of Practice and Procedure of the Federal Energy Regulatory Commission ("FERC"), 18 C.F.R. § 385.216, Pinnacle West Energy Corporation ("PWE"), hereby withdraws its Application for Determination of Exempt Wholesale Generator ("EWG") Status, which PWE filed with FERC in the above-captioned docket on March 28, 2001, as amended and supplemented on April 27, 2001. No parties have intervened or protested the PWE application, so no party will be prejudiced or otherwise affected by PWE's withdrawal.

Rule 216 of the Commission's Rules of Practice and Procedure provides that a party's withdrawal of a pleading shall become effective 15 days after the date on which the withdrawal was filed. PWE requests waiver of the provisions of 18 C.F.R. § 385.216 to allow the Notice of Withdrawal to become effective as of the date of this filing.[1]

Good cause exists to waive the provisions of 18 C.F.R. § 385.216. On September 12, 2000, Pinnacle West Capital Corporation ("PNW") filed an application pursuant to Section 9(a)(2) of the Public Utility Holding Company Act of 1935 requesting approval from the Securities and Exchange Commission ("SEC") in connection with a proposed corporate reorganization involving the transfer of Arizona Public Service Company's fossil generating assets to PWE and PWE's operation of other generating facilities currently being developed. Approval was requested because it would result in PWE becoming a public-utility company.

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[1] *See Southern Natural Gas Company*, 76 FERC ¶ 61,121 (1996) (waiving 15-day requirement of 18 C.F.R. § 385.216 to avoid delay in construction of facilities).

PWE stated in its initial EWG Application that it intended to maintain its EWG status only until the SEC authorized it to become a public-utility company. On April 27, 2001, the SEC issued an order authorizing PNW to establish PWE as a public-utility company. For this reason, PWE is filing this Notice of Withdrawal and no further Commission action is requested.

Respectfully submitted,

Mary Ann K. Huntington
Andrea J. Weinstein
Morgan, Lewis & Bockius, LLP
1800 M Street, N.W.
Washington, D.C. 20036
Tel: (202) 467-7622/7332

Attorneys for
Pinnacle West Energy Corporation

Dated: May 2, 2001

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Pinnacle West Energy Corporation) **Docket No. EG01-163-000**

NOTICE OF FILING

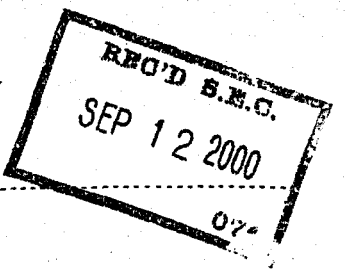
(May __, 2001)

On May 2, 2001, Pinnacle West Energy Corporation ("PWE") filed with the Federal Energy Regulatory Commission a Notice of Withdrawal of its Application for Determination of Exempt Wholesale Generator ("EWG") Status. PWE states that no parties have intervened or protested the PWE EWG Application, so no party will be prejudiced or otherwise affected by PWE's withdrawal. PWE requests that its Notice of Withdrawal become effective as of the date of filing.

Any person desiring to be heard or to protest said filing should file a motion to intervene or comments with the Federal Energy Regulatory Commission, 888 First Street, N.E., Washington, D.C. 20426, in accordance with Rules 211 and 214 of the Commission's Rules of Practice and Procedures (18 C.F.R. § 385.211 and 18 C.F.R. § 385.214). The Commission will limit its consideration of comments to those that concern the adequacy or accuracy of the application. All such motions and comments should be filed on or before _____, 2001. Any person wishing to become a party must file a motion to intervene. Copies of this filing are on file with the Commission and are available for public inspection. This filing may also be viewed on the Internet at http://www.ferc.fed.us/online/rims.htm (call 202-208-2222 for assistance).

David P. Boergers
Secretary

UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
WASHINGTON, D.C. 20549



FORM U-1
APPLICATION
UNDER
THE PUBLIC UTILITY HOLDING COMPANY ACT OF 1935

PINNACLE WEST CAPITAL CORPORATION
400 East Van Buren Street, Suite 700
Phoenix, Arizona 85004

(Name of company filing this statement and address of principal executive offices)

None

(Name of top registered holding company parent)

Herbert I. Zinn
Pinnacle West Capital Corporation
400 North Fifth Street
Mail Station 8695
Phoenix, Arizona 85004

Mary Ann K. Huntington
Morgan, Lewis & Bockius LLP
1800 M Street, N.W.
Washington, D.C. 20036

(Name and address of agents for service)

The Commission is requested to send copies of all notices, orders, and communications in connection with this Application to:

Herbert I. Zinn
Pinnacle West Capital Corporation
400 North Fifth Street
Mail Station 8695
Phoenix, Arizona 85004

Mary Ann K. Huntington
Morgan, Lewis & Bockius LLP
1800 M Street, N.W.
Washington, D.C. 20036

EXHIBIT A-3

EXPEDITED
AZ CORP COMMISSION
FILED
0899205-3
SEP 27 3 16 PM '99

ARTICLES OF INCORPORATION

OF

PINNACLE WEST ENERGY CORPORATION

APPR PA-71B NAIC
DATE APPR 09-22-99
TERM
DATE TIME

FIRST: The name of the corporation is Pinnacle West Energy Corporation.

SECOND: The purpose for which the corporation is organized is the transaction of any or all lawful business for which corporations may be incorporated under the laws of the State of Arizona, as they may be amended from time to time. The character of business which the corporation initially intends actually to conduct in the State of Arizona is development, production and sale of wholesale energy.

THIRD: The aggregate number of shares that the corporation shall have authority to issue is One Hundred (100) common shares, all of which shares shall be of a single class and shall have a par value of $.01 per share.

FOURTH: The name and street address in Arizona of the initial statutory agent of the corporation is CT Corporation System, 3225 North Central Avenues, suite 1601, Phoenix, Arizona 85012. The street address of the initial known place of business of the corporation in Arizona is 400 North 5th Street, Station 9068, Phoenix, Arizona 85004.

FIFTH: The number of directors constituting the initial board of directors of the corporation is two (2). The names and addresses of the persons who are to serve as directors until the first annual meeting of shareholders, or until their successors are elected and qualified, are:

Name	Address
William J. Post	400 North Fifth Street Phoenix, AZ 85004
William L. Stewart	400 North Fifth Street Phoenix, AZ 85004

The number of persons to serve on the board of directors thereafter shall be fixed by the bylaws of the corporation.

SIXTH: The name and address of the incorporator is Pinnacle West Capital Corporation, 400 East Van Buren, Phoenix, Arizona 85004.

SEVENTH: The liability of a director or former director to the corporation or its shareholders shall be eliminated to the fullest extent permitted by Section 10-202.B.1 of the Arizona Revised Statutes.

If the Arizona Business Corporation Act is amended to authorize corporate action further eliminating or limiting the liability of directors, the liability of a director of the corporation shall be eliminated or limited to the fullest extent permitted by the Arizona Business Corporation Act, as amended.

Any repeal or modification of this Article Seventh shall not adversely affect any right or protection of a director of the corporation existing hereunder with respect to any act or omission occurring prior to or at the time of such repeal or modification.

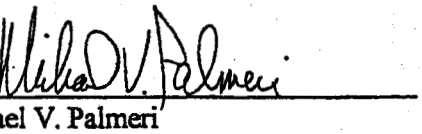
The provisions of this Article Seventh shall not be deemed to limit or preclude indemnification of a director by the corporation for any liability of a director which has not been eliminated by the provisions of this Article Seventh.

EIGHTH: The corporation shall indemnify any and all of its existing and former directors and officers to the fullest extent permitted by Section 10-202.B.2 of the

Arizona Business Corporation Act. If the Arizona Business Corporation Act is amended to authorize corporate action broadening the corporation's ability to indemnify its directors and officers, the corporation shall indemnify its existing and former directors and officers to the fullest extent permitted by the Arizona Business Corporation Act, as amended. Any repeal or modification of this Article Eighth shall not adversely affect any right or protection of any existing or former director or officer of the corporation existing hereunder with respect to any act or omission occurring prior to or at the time of such repeal or modification.

DATED: September 27, 1999

PINNACLE WEST CAPITAL CORPORATION

By: 

Michael V. Palmeri
Vice President/Finance
Incorporator

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EXHIBIT B-1

TERM SHEET

The following is a summary of all material terms and conditions relating to the relocation by Arizona Public Service Company, an Arizona corporation ("APS") of its

a. electric generating business and assets (the "Generating Assets"), as more particularly defined below, which will be moved to APS's affiliate, Pinnacle West Energy Corporation, an Arizona corporation ("PWEC"); and

b. bulk power marketing and trading assets (the "Bulk Power Assets") which will be moved to Pinnacle West Capital Corporation, an Arizona corporation ("PWCC"),

in conjunction with an overall corporate reorganization by PWCC, APS's parent company, which is, in substantial respect, undertaken in furtherance of a Settlement Agreement, dated May 14, 1999, and approved by the Arizona Corporation Commission (the "ACC") on October 6, 1999 in its Decision No. 61973.

Executive Summary:

In furtherance of an overall corporation reorganization, APS intends to move its

a. Generating Assets, as described below, in two (2) stages, to two (2) newly created subsidiaries (respectively, "Subsidiary A" and "Subsidiary B") that will each be merged into PWEC; and

b. Bulk Power Assets that will be relocated to PWCC.

The bulk of APS's Fossil Assets and Solar Assets (as defined below) will be moved to Subsidiary A by January 1, 2001, and APS's Nuclear Assets (as defined below) will be moved to Subsidiary B by December 31, 2002. APS's Bulk Power Assets will be moved to PWCC by January 1, 2001.

Simultaneously with each stage of the relocation of Generating Assets, APS will divest itself of its ownership interest in Subsidiary A and Subsidiary B, respectively, by transferring the common stock of each subsidiary to PWCC. PWCC will then merge each subsidiary into its wholly owned subsidiary, PWEC, thereby completing the move of APS's Generating Assets to its affiliate, PWEC. Any Fossil Assets, as defined below, that are not moved to PWEC by January 1, 2001, will be moved to PWEC using a similar subsidiary transaction by December 31, 2001. The Bulk Power Assets will be moved directly to PWCC.

As a result of this corporate reorganization, by January 1, 2003, APS shall be engaged in the transmission and distribution of electricity in the State of Arizona, and will no longer be engaged in the generation of electricity. PWEC shall be engaged in the generation and sale of electricity to wholesale customers in the region bounded by the Western States Coordinating

Council. By January 1, 2001, PWCC will assume the bulk power marketing and trading activities that were previously conducted by APS.

The Plan of Reorganization

1. **Generating Assets:**

   1.1. Palo Verde Nuclear Generating Station – Wintersburg, Arizona
   1.2. Four Corners Generating Station – Fruitland, New Mexico
   1.3. Navajo Generating Station – Page, Arizona
   1.4. Cholla Generating Station – Joseph City, Arizona
   1.5. West Phoenix Generating Station – Phoenix, Arizona
   1.6. Ocotillo Generating Station – Tempe, Arizona
   1.7. Saguaro Generating Station – Red Rock, Arizona
   1.8. Yucca Generating Station – Yuma, Arizona
   1.9. Douglas/Fairview Generating Station – Douglas, Arizona
   1.10. Various grid-connected solar generating facilities located in the State of Arizona

   Item 1.1 is referred to herein as the "Nuclear Assets."
   Items 1.2 through 1.9 are referred to herein as the "Fossil Assets."
   Item 1.10 is referred to herein as the "Solar Assets."

   Bulk Power Assets

   Various agreements relating to the purchase and sale of bulk electric power, emission allowances, natural gas, and other energy-related commodities, together with infrastructure and related items of tangible personal property used or useful in connection with the conduct of bulk power trading activities.

2. **Established Asset Value:**

   For purposes of the reorganization, the Generating Assets and the Bulk Power Assets will be valued at APS's book value as of the Closings referred to in Sections 3.1.1 and 3.1.2, below.

3. **Other Material Terms and Conditions:**

   3.1 Effective Dates:

   3.1.1 The bulk of the Fossil Assets, the Solar Assets and the Bulk Power Assets will be moved on or before January 2, 2001. Any remaining Fossil Assets will be moved by December 31, 2001.

   3.1.2 The Nuclear Assets will be moved by December 31, 2002.

   3.2 Conditions and Approvals Required as a Condition of the Reorganization:

3.2.1 Third Party Approvals and Consents: The reorganization will be subject to certain approvals and consents:

3.2.1.1 Participant approvals, to the extent applicable, for the Four Corners Generating Station, Navajo Generating Station and Palo Verde Nuclear Generating Station.

3.2.1.2 Third party consents to assignment and transfer of various contracts, licenses, leases, easements, permits, etc., necessary and useful for the operation of the assets being transferred (*e.g.*, goods and services).

3.2.2 Regulatory Requirements: The reorganization will be subject to certain regulatory requirements:

3.2.2.1 Federal Energy Regulatory Commission ("FERC") approval under Section 203 of the Federal Power Act.

3.2.2.2 Receipt of favorable letter rulings from the Internal Revenue Service that the proposed reorganization will be tax free.

3.2.2.3 Final approval by the Securities Exchange Commission, pursuant to Section 9(a)(2) of the Public Utility Holding Company Act ("PUHCA"), that PWCC, as an exempt holding company, may acquire an interest in PWEC, a public utility for purposes of PUHCA; or alternatively, a determination by the FERC that PWEC is an exempt wholesale generator under Section 32 of PUHCA.

3.2.2.4 Permit transfer approvals from various Federal, State and local environmental regulatory authorities.

3.2.2.5 Approval by the Nuclear Regulatory Commission of the transfer of the Palo Verde Nuclear Generating Station Operating License from APS to PWEC.

3.2.3 Other Conditions

On the effective dates of the reorganization, indicated above, the parties will deliver all appropriate instruments and documents as necessary to accomplish the relocation of the Generating Assets and Bulk Power Assets to PWEC and PWCC, respectively, including necessary instruments of title and assignments of all contracts, permits, authorizations, leases, water rights, easements and rights-of-way used and useful to ownership or operation of the Assets.

EXHIBIT D-1

1800 M Street, N.W.
Washington, D.C. 20036-5869
202-467-7000
Fax: 202-467-7176

Morgan, Lewis & Bockius LLP
COUNSELORS AT LAW

July 28, 2000

Honorable David P. Boergers, Secretary
Federal Energy Regulatory Commission
888 First Street, N.E.
Washington, D.C. 20426

Re: Application of Arizona Public Service Company, Pinnacle West Capital Corporation, and Pinnacle West Energy Corporation for Authorization to Transfer Jurisdictional Facilities, Docket No. EC00- -000

Dear Secretary Boergers:

Pursuant to Section 203 of the Federal Power Act, 16 U.S.C. § 824b (1994), and Part 33 of the regulations of the Federal Energy Regulatory Commission, 18 C.F.R. Part 33, Arizona Public Service Company ("APS"), Pinnacle West Capital Corporation ("PWCC"), and Pinnacle West Energy Corporation ("PWE") (jointly "Applicants"), hereby submit for filing six copies of an Application for Authorization to Transfer Jurisdictional Facilities.

Applicants are making this filing in connection with the proposed corporate restructuring of APS, under which APS will separate its generation and wholesale marketing businesses, from its transmission and distribution businesses. Applicants developed the restructuring plan in order to comply with the Arizona retail choice program, which provides for the introduction of customer choice for retail customers, and requires APS to divest its generation assets. As demonstrated in the body of the Application, the proposed transfer of jurisdictional facilities raises no competitive or other concerns, and is in the public interest.

A form of notice suitable for publication in the *Federal Register* and a copy of the notice on a computer diskette are attached hereto. Applicants have served a copy of this Application on the Arizona Corporation Commission and the New Mexico Public Regulation Commission. In addition, copies of this transmittal letter have been sent to all customers under each of the wholesale power sales contracts, tariffs, and service agreements that APS seeks authorization under Section 203 to transfer to an affiliate.

Any of these customers that desire a copy of the Application should contact the undersigned.

If you have any questions about this filing, please feel free to contact me.

Respectfully submitted,

John D. McGrane
Morgan, Lewis & Bockius LLP
1800 M Street, N.W.
Washington, D.C. 20036-5869
Phone: (202) 467-7000

Barbara M. Champion, Senior Attorney
Pinnacle West Capital Corporation
P.O. Box 53999
Mail Station 8695
Phoenix, Arizona 85072-3999
Phone: (602) 250-3547

Attorneys for
Arizona Public Service Company
Pinnacle West Capital Corporation
Pinnacle West Energy Corporation

Enclosures

cc: Arizona Corporation Commission
New Mexico Public Regulation Commission

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Arizona Public Service Company	)	Docket No. EC00-_____
Pinnacle West Capital Corporation	)	
Pinnacle West Energy Corporation	)	

APPLICATION OF
ARIZONA PUBLIC SERVICE COMPANY,
PINNACLE WEST CAPITAL CORPORATION, AND
PINNACLE WEST ENERGY CORPORATION
FOR AUTHORIZATION TO TRANSFER
JURISDICTIONAL FACILITIES

I. INTRODUCTION

Arizona Public Service Company ("APS"), and its affiliates Pinnacle West Capital Corporation ("PWCC") and Pinnacle West Energy Corporation ("PWE") (collectively, "Applicants"), submit this Application to obtain the approvals necessary to separate APS's generation and wholesale marketing businesses from its transmission and distribution businesses. APS is separating its generation and marketing functions from its transmission and distribution functions, in accordance with the Arizona retail choice program and as the means of implementing the Settlement Agreement approved by the Arizona Corporation Commission ("ACC") which calls for the divestiture of APS's generation assets. Upon completion of the proposed corporate restructuring, PWE will own and operate APS's existing generating plants, and APS will become a "wires" company, owning and operating transmission and distribution facilities. PWCC will have a Marketing and Trading Department and act as a power marketer, and conduct trading and brokering functions on behalf of its subsidiaries APS, PWE, and APS Energy Services Company, Inc. ("APSES").

Under Section 203 of the Federal Power Act, 16 U.S.C. § 824b (1994), and Part 33 of the Federal Energy Regulatory Commission's ("FERC" or the "Commission") Regulations, 18 C.F.R. §§ 33.1-33.10 (1999), Applicants seek authorization for:

1. the transfer from APS to PWE, directly or indirectly, of certain jurisdictional facilities;

2. the transfer from APS to PWE, directly or indirectly, of certain operational agreements to PWE; and

3. the transfer from APS to PWCC of certain wholesale power sales contracts, APS's Electric Coordination Tariff and accompanying service agreements, and certain service agreements under APS's Market-Rate Tariff including any new agreements APS enters into under its market-rate tariff up to and until the time of transfer.

Upon the transfer of APS fossil generation resources to PWE, contemplated to occur on or before January 1, 2001, PWE will sell the output from its generation resources to PWCC. Under the restructuring plan, PWCC will, in turn, provide APS with all of its generation-related ancillary services pursuant to agreements to be filed with the Commission.[1] These arrangements will allow APS to continue providing ancillary services at the existing rates in its OATT until a market for ancillary services develops in Arizona.

[1] Specifically, PWE intends to file an application for authorization to sell power at market-based rates in a separate but concurrent filing. At that time, PWE will also file an agreement for the sale of generation related ancillary services to PWCC at exactly the same rates that APS currently charges transmission customers under its OATT. To the extent additional generation related ancillary services may be required by the Commission or pursuant to protocols to be filed by the Arizona Independent System Administrator, PWE will supply those services to PWCC. PWCC will then in turn provide ancillary services to APS, again at the same rates currently charged by APS under its OATT. PWE and PWCC will reserve the right to change such rates and services as their costs of providing such service change, or as conditions warrant.

II. REQUEST FOR EXPEDITED APPROVAL AND REQUESTED EFFECTIVE DATES

The approvals that Applicants request are necessary to implement Arizona's retail choice plan for the Applicants. Accordingly, Applicants request that the Commission issue an order no later than November 30, 2000, approving the Section 203 application and request expedited consideration to the extent necessary. Applicants note that they anticipate transferring most of the assets and personnel at year-end, in order to facilitate calendar year record keeping, and believe that the time between the requested approval date of November 30 and the contemplated transfer is necessary to allow the transfer of personnel and to implement other aspects of the transaction. Applicants will promptly notify the Commission upon the consummation of the transactions described herein.

III. PROPOSED RESTRUCURING PLAN OF THE APPLICANTS

A. Description of the Parties

PWCC: PWCC is an Arizona corporation whose principal place of business is located at 400 North 5th Street, Phoenix, Arizona. PWCC is a holding company that is exempt from registration under the Public Utility Holding Company Act of 1935, as amended ("PUHCA"), by virtue of Section 3(a)(1) of PUHCA and Rule 2 of the regulations of the Securities and Exchange Commission ("SEC"). PWCC is the parent company of APS, PWE, and APSES. At present, PWCC has no electric-utility company subsidiaries, other than APS. PWCC has two non-utility subsidiaries, El Dorado Investment Company, an investment firm with a portfolio consisting of venture capital, limited partnerships, and other holdings, and SunCor Development Company, a real estate developer invested in planned communities and commercial/industrial projects.

PWCC is also a power marketer. On June 20, 2000, the Commission conditionally accepted for filing a proposed market-based rate tariff and code of conduct for PWCC in Docket No. ER00-2268-000. As ordered by the Commission, PWCC submitted a compliance filing to resolve the remaining concerns of the Commission regarding potential affiliate abuse and the effect of affiliate transactions on captive wholesale customers with fuel adjustment clauses. PWCC will market power and energy that it purchases and will engage in wholesale marketing and brokering activities.

APS: APS is a public service corporation organized under the laws of the State of Arizona, engaged in the business of generating, transmitting and distributing electricity in all or part of eleven of Arizona's fifteen counties. APS owns or partially owns a number of generating assets. A list of the transmission assets that APS is transferring to PWE is included as Attachment A. The transmission assets being transferred are facilities functionalized to production – such as step-up transformers and related equipment. A list of the contracts that APS will be transferring to PWE and PWCC is included in Attachment B. APS is authorized to sell wholesale power and energy at market-based rates.[2] In its order granting market-base rate authority to APS, the Commission found that APS does not possess market power.[3] APS has an OATT on file with the Commission.[4]

PWE: PWE was formed as a subsidiary of its parent company, PWCC, for the purpose of owning and operating wholesale generating facilities. PWE was incorporated

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2 *See Arizona Public Service Co.*, 79 FERC & 61,022 (1997). APS recently filed an updated market analysis concerning its market-based rates. *See Arizona Public Service Co.*, Docket No. ER00-1875-000 (March 14, 2000).

3 *See Arizona Public Service Co.*, 79 FERC & 61,022, at 61,098-99.

4 Docket Nos. OA96-153-000, ER96-2401-000.

in Arizona on September 27, 1999, and currently has no operating generating facilities that are subject to the Commission's jurisdiction. Upon transfer of APS's generating assets to PWE, PWE will become a generating company[5] and APS will become primarily a wires company. PWE will generally sell the output from its generating facilities to PWCC but may sell a portion to other wholesale customers.

Diagrams showing the corporate relationships between PWCC, APS, and PWE before and following consummation of the transaction are attached as Appendices A and B.

B. Arizona Restructuring

The Applicants developed the restructuring plan in response to the changes currently underway in the wholesale and retail sectors of the electric and gas industries in Arizona and elsewhere. Specifically in Arizona, the ACC has implemented a plan and rules to permit retail access. On October 6, 1999, the ACC approved a Settlement Agreement between APS and several customer groups and consumer advocates resolving retail electric competition-related issues and approving unbundled tariffs.[6] Under the terms of the Electric Competition Rules of the ACC and APS's Settlement Agreement, retail choice for APS's retail customers is being phased-in. All of APS's retail customers will be entitled to choose their retail power supplier beginning January 1, 2001.[7] Remaining retail customers of APS taking service under "standard offer" bundled rates

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[5] PWCC currently anticipates seeking approval from the Securities and Exchange Commission ("SEC") under Section 9(a)(2) of Public Utilities Holding Company Act of 1935, as amended ("PUHCA"), in connection with the transfer since it will result in PWE becoming a public-utility company; alternatively, PWE will file for exempt wholesale generator status under Section 32 of PUHCA.

[6] ACC Decision No. 61973.

[7] *See* Attachment D - ACC approved Settlement Agreement, § 1.1.

will be subject to planned rate reductions that will continue until July, 2004.[8] Under the Settlement Agreement, APS is entitled to apply for a change in the agreed upon rate reductions only in the event of an emergency or a material change in its cost of service as a result of specified extraordinary events. The approved Settlement Agreement also requires that APS divest its generation assets by December 31, 2002, but allows APS to divest its assets to an affiliate.[9]

C. Applicants Plan to Implement Arizona Restructuring

In response to the state restructuring proceedings, PWCC formed APSES, a marketer of electricity and energy-related services to primarily retail customers in Arizona and California, and PWE, a corporation formed to engage in the business of owning and operating generating facilities in Arizona and elsewhere. To further comply with state restructuring, APS is now transferring its existing generating assets, and requesting the authority to transfer associated transmission plant, and existing generation operating agreements to PWE. Additionally, APS is requesting the authority to transfer certain existing wholesale power sales agreements to PWCC.

To implement the actual transfer of facilities after Commission approval, APS intends the following transactions. As previously mentioned APS and PWE are direct and wholly-owned subsidiaries of PWCC. New subsidiaries will be created as needed to implement the transfer of facilities. The following transactions will occur on or about January 1, 2001, pursuant to a plan of reorganization. First, APS will contribute its fossil and applicable solar generation assets and its operational agreements to one or more of these newly formed subsidiaries (hereafter all will be referred to as a "Transitory

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[8] *See* Attachment D - ACC approved Settlement Agreement, §§ 2.2, 2.6, 2.7.

[9] *See* Attachment D - ACC approved Settlement Agreement, § 4.1.

Subsidiaries"). This transaction is intended to qualify as a tax-deferred reorganization under IRC Section 368(a)(1)(D). Second, APS will distribute or cause to be distributed all of the stock of a Transitory Subsidiary to PWCC in a transaction intended to qualify as a tax-deferred spin-off under IRC Section 355. Third, under state law, the Transitory Subsidiary will then be merged into PWE (with PWE surviving) in a transaction intended to qualify as a tax-deferred statutory merger under IRC Section 368(a)(1)(A). It is contemplated that the three aforementioned transactions will occur simultaneously.

APS also intends to transfer certain wholesale power contracts to PWCC in a similar manner as described above with the use of a different subsidiary (in this case, the subsidiary will be merged into PWCC). Following approval of such transfer, APS will transfer the contracts and, as required in Section 35.16 of the Commission's regulations, file a Notice of Succession within 30 days. At that time, APS will refile each agreement with the Commission in accordance with the Commission's recent ruling on rate schedule designations.[10]

The transfer of the APS nuclear facilities is contemplated to occur by the end of 2002 pursuant to the current plan of reorganization. APS intends to use the same mechanism as described above for the other generating assets for transferring the nuclear assets to PWE. The delay in transferring the nuclear assets is to ensure additional time to adequately address complicated contractual arrangements, such as sale/leaseback provisions, in place amongst the various owners of the nuclear facilities. There are also certain financial and economic considerations that must be resolved before the actual transfer of nuclear assets can take place. APS will inform the Commission when the

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10 *See Designation of Electric Rate Schedule Sheets*, Order No. 614, 90 FERC & 61,352 (2000).

actual transfer of its nuclear generating units takes place.

The proposed restructuring plan of the Applicants will help PWCC and its affiliates adapt their electric businesses to new and changing markets. The restructuring plan will allow PWCC and its affiliates to better compete in these markets and permit better service for customers and shareholders.

IV. APPLICATION PURSUANT TO SECTION 203

Section 203 of the FPA requires Commission approval for the disposition of facilities that are subject to the Commission's jurisdiction and have value in excess of $50,000. APS owns and operates step-up transformers and associated transmission facilities at its generating facilities that will be included in the direct or indirect transfer of assets to PWE. APS also has existing wholesale contracts that will be transferred to PWCC and PWE and these contracts are considered "facilities." *See Enron Power Marketing, Inc.*, 65 FERC ¶ 61,305 (1993). Accordingly, the instant transaction involves a disposition of jurisdictional facilities requiring Commission approval. The Commission will approve such a disposition if it concludes that the transaction is consistent with the public interest. *See, e.g., Boston Edison Co.*, 80 FERC ¶ 61,274 (1997). In analyzing the effect of the disposition on the public interest, FERC generally considers the following three factors: (1) the effect on competition, (2) the effect on rates, and (3) the effect on regulation. As shown below, the proposed transfer of jurisdictional assets is in the public interest. The transfer will actually benefit the public interest, as it will facilitate the restructuring of the electric power industry in Arizona by (1) finalizing the implementation of retail access in Arizona as promulgated by the ACC, (2) allowing competition in the generation markets, and (3) enabling APS to operate its transmission system as a "wires" only company.

A. The Effect on Competition

The restructuring plan of the Applicants reflects the type of structural changes that are becoming typical in the evolving competitive electric marketplace. The restructuring will properly align the generation business into one unit, the transmission and distribution business into another, and the wholesale power marketing function in still another unit. Such an alignment will be beneficial to the competitive marketplace because it will allow each entity to focus exclusively on its core business. Because this restructuring is internal to the Pinnacle West corporate family, there are no competitive impacts from the transfers contemplated herein. *See, e.g., PECO Energy Co.*, 90 FERC ¶ 61,269, at 61,903 (2000); *Public Svc. Elec. & Gas, Co.*, 88 FERC ¶ 61,299, at 61,916 (1999) (finding that similar internal restructuring did not increase market concentration or affect competition).

Additionally, APS has had market rate approval for the past three years. On May 2, 2000, an updated market power study by APS was accepted by the Commission in Docket No. ER00-1875-000. The updated report shows that APS does not possess market power in the generation or transmission markets. In addition, PWCC recently received conditional approval for a market-based tariff in Docket No. ER00-2268-000.[11] Finally, PWE is filing for market-based rate approval in a separate but concurrent filing. Since neither APS, PWCC, or PWE possess market power in generation or transmission markets, the transfer of assets should not create any competitive issues. In fact, providing a competitive alternative for generation resources in the retail and wholesale markets, the transfer of assets will further competition to the benefit of all customers.

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[11] As noted previously in III.A, on July 13, 2000, APS and PWCC submitted a compliance filing to address the sole remaining concern of the Commission regarding the treatment of APS's captive wholesale customers with fuel adjustment clauses.

B. The Effect on Rates

The transfer of assets should not affect the rates currently paid by retail and wholesale customers. APS does not intend to change its transmission rates, since none of the transmission assets being transferred to PWE are currently in APS's transmission rates reflected in its OATT. In order to deliver the output of the PWE generating assets, the entity purchasing the power will be required to use transmission service pursuant to APS's OATT.

As stated previously, the retail customers of APS are protected by rate reductions through July, 2004 and all retail customers will be able by January 1, 2001 to choose their electric supplier. Most of APS's wholesale transactions are currently conducted under market-based rates or through the Western System Power Pool and the transfer of assets should have no effect on their competitive rates. APS does have some cost-based wholesale rate customers, of which all but two can readily choose alternate power suppliers. APS does not believe the transfer of assets will harm its current wholesale customers. APS recently proposed measures that will protect wholesale customers from any potential affiliate abuse associated with affiliated transactions. To protect existing customers with system incremental cost (SIC) in their pricing provisions, APS will cap the pass-through of cost at the lesser of SIC or prices based on the Palo Verde Index. For customers with a fuel adjustment clause (FAC) in their contracts, APS has proposed that the customers would pay the lesser of a FAC calculated with inter-affiliate transactions included, a FAC calculated with the inter-affiliate transactions priced not as actual but at the Palo Verde Index price for a similar duration, or the average of the actual corrected FAC for the same month for 1998 or 1999 (*See Pinnacle West Capital Corporation*, Docket No. ER00-2268-000). These protections will continue in place.

In addition, further protection to all customers regarding ancillary services will be provided. In separate Section 205 filings, appropriate agreements will be filed with the Commission that will provide APS with its generation related ancillary services. Inasmuch as the charges for such ancillary services currently included in APS's OATT are based on the fossil generation units to be transferred from APS to PWE, the costs associated with providing these ancillary services will be unchanged when the units are transferred. Upon the transfer of the assets, PWE will sell generation-related ancillary services to PWCC at rates identical to those in APS's OATT, and under a separate agreement, PWCC in turn will provide APS with its generation-related ancillary services at exactly the same charges. Under this arrangement APS is ensured of obtaining all its generation-related ancillary services, and will merely pass through to customers subscribing to such services the costs APS incurs for these services at exactly the same rates currently in APS's OATT. Indeed, by PWE becoming a separate entity with the above-mentioned safeguards, competition in the generation market should expand, and all customers should benefit.

C. The Effect on Regulation

The Commission requires Applicants under Section 203 to evaluate the effect of a proposed transaction on regulation at both the Federal and state level. The Commission is mainly concerned with instances where (1) the transaction will shift regulatory authority from the Commission to the SEC or otherwise diminish Commission authority; or (2) the affected state commissions will not have authority to act on the proposed transaction.[12]

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[12] *See Inquiry Concerning the Commission's Merger Policy Under the Federal Power Act: Policy Statement*, Order No. 592, FERC Stats. & Regs. & 30,110 (1996), at 30,124-25.

UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
WASHINGTON, D.C. 20549

FORM U-1
APPLICATION
UNDER
THE PUBLIC UTILITY HOLDING COMPANY ACT OF 1935

PINNACLE WEST CAPITAL CORPORATION
400 East Van Buren Street, Suite 700
Phoenix, Arizona 85004

(Name of company filing this statement and address of principal executive offices)

None

(Name of top registered holding company parent)

Herbert I. Zinn
Pinnacle West Capital Corporation
400 North Fifth Street
Mail Station 8695
Phoenix, Arizona 85004

Mary Ann K. Huntington
Morgan, Lewis & Bockius LLP
1800 M Street, N.W.
Washington, D.C. 20036

(Name and address of agents for service)

The Commission is requested to send copies of all notices, orders, and communications in connection with this Application to:

Herbert I. Zinn
Pinnacle West Capital Corporation
400 North Fifth Street
Mail Station 8695
Phoenix, Arizona 85004

Mary Ann K. Huntington
Morgan, Lewis & Bockius LLP
1800 M Street, N.W.
Washington, D.C. 20036

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Pursuant to Sections 9(a)(2) and 10 of the Public Utility Holding Company Act of 1935 (the "Act"), Pinnacle West Capital Corporation, an Arizona corporation ("PNW"), hereby requests approval from the Securities and Exchange Commission (the "Commission") to establish a new public-utility company subsidiary in connection with the proposed corporate reorganization (the "Reorganization") involving the relocation of certain generation assets from Arizona Public Service Company ("APS"), PNW's existing public-utility company subsidiary, to Pinnacle West Energy Corporation ("PWE"), another wholly-owned subsidiary of PNW. As a result of this Reorganization, PWE will become an "electric utility company" and a "public-utility company" within the meaning of the Act, and, therefore, PNW will acquire an additional public-utility subsidiary. (However, PWE will not become a public service corporation under Arizona state law.) PNW will continue to meet the requirements for an intrastate exemption under Section 3(a)(1) of the Act and will continue to file annual exemption statements on Form U-3A-2 pursuant to Rule 2 of the Commission's regulations.

The purpose of the Reorganization is to comply with certain requirements set forth in rules adopted by the Arizona Corporation Commission ("ACC") that provide the framework for introduction of retail electric competition in Arizona (the "Competition Rules"), and in a final ACC order approving the APS' settlement with various parties with respect to implementation of the Competition Rules (the "Settlement"). Pursuant to the Competition Rules and the Settlement, APS must separate its generating assets and competitive services from its transmission and distribution functions no later than December 31, 2002. PNW seeks Commission approval now, however, because APS intends to move a substantial portion of its generating assets to PWE on or before January 1, 2001. There may be some delays in moving particular assets from APS to PWE, pending receipt by APS of certain consents or waivers from third parties with respect to such assets, but most of the non-nuclear generating assets are to be moved to PWE on or before January 1, 2001.

ITEM 1 DESCRIPTION OF PROPOSED TRANSACTION

A. Description of the Parties

1. **Pinnacle West Capital Corporation:** PNW was incorporated in 1985 under the laws of the State of Arizona. Through its subsidiaries, PNW is engaged in the generation, transmission, and distribution of electricity and the sale of energy services. Also through subsidiaries, PNW is involved in real estate development and in venture capital investment. On December 31, 1999, PNW employed approximately 7,534 people, including the employees of its subsidiaries. Of these employees, 6,234 were employees of its existing public-utility subsidiary, APS, and employees assigned to joint projects of APS where APS services as a project manager. PNW's principal executive offices are located at 400 East Van Buren, Phoenix Arizona 85004. PNW is currently a public-utility holding company exempt from the provisions of the Act, except Section 9(a)(2), by reason of its filing of annual exemption statements on Form U-3A-2 pursuant to Rule 2 of the Commission's regulations. 17 C.F.R. § 250.2(a). PNW's direct, wholly-owned subsidiaries are described below and a copy of PNW's most recent Form U-3A-2 is attached as Exhibit G-1.

2. **Arizona Public Service Company:** APS is a public-utility company incorporated in 1920 under the laws of the State of Arizona. APS is a wholly-owned subsidiary of PNW. APS' principal executive offices are located at 400 North Fifth Street, Phoenix Arizona 85004. APS provides retail electric services principally in the State of Arizona and is actively engaged in the competitive wholesale electric markets. APS is subject to regulation by the ACC with respect to retail rates, accounting, service standards, service territory, issuances of securities, siting, of generation and transmission projects and various other matters.

APS is also subject to the jurisdiction of the Federal Energy Regulatory Commission ("FERC") under Parts I, II, and III of the Federal Power Act for certain phases of its business,

including regulation of its rates relating to wholesale sales of energy and interstate transmission, licensing its hydroelectric stations, accounting, and certain other matters. APS' current business structure consists of three primary business units: generation; power marketing; and transmission/distribution. The following briefly describes these business units.

a. ***Generation*** -- APS currently owns or leases generating facilities with a total accredited capacity of approximately 4,000 megawatts. The fuel mix of APS' generation capacity is 41.8% coal; 31.5% gas or oil; 26.5% nuclear; and less than 1% other. APS' sources of energy during 1999 were approximately 56.8% from its own generation resources and approximately 43.2% from purchased power. The Reorganization involves the relocation of a substantial portion of APS' generating facilities and related facilities, as well as the transfer of certain of the employees of APS' generation business unit. The generating assets being moved to PWE on or before January 1, 2001 are briefly described below.[1] Also, attached, as Exhibit E-1, is a map showing the location of each of APS' generation facilities.

[1] In addition to the generating facilities to be moved by January 1, 2001, APS also owns or leases an interest in the Palo Verde Nuclear Generating Station ("PVNGS"), a three-unit nuclear generating facility located in Wintersburg, Arizona approximately 55 miles west of Phoenix, Arizona. The total accredited capacity of PVNGS is 3,733 megawatts, of which APS owns or leases 29.1%, or approximately 1,086 megawatts. APS is also the operator of the facility. There are six other co-owners of PVNGS, which collectively own or lease the remaining 70.9%. Ownership is in the form of a co-tenancy, and the co-owners are not affiliates of one another. APS operates PVNGS pursuant to an agreement in which each owner pays its proportionate share of the cost of operating the facility. While the Reorganization involving APS' non-nuclear generating facilities is contemplated to occur on or before January 1, 2001, APS does not plan to move its interest in PVNGS to PWE until 2002. The delay in moving the nuclear assets is to ensure additional time to adequately address complicated contractual arrangements, such as sale and leaseback provisions between APS and certain owner trusts to which APS has sold and leased back a portion of its interest in PVNGS Unit 2 and the PVNGS common facilities. There are also certain financial and economic considerations that must be resolved before the nuclear assets can be moved to PWE.

Four Corners Power Plant ("Four Corners"):

Four Corners is a five-unit coal fired power plant located near Farmington, New Mexico on the Navajo Reservation. The property underlying the plant is held under easements granted by the federal government and under leases from the Navajo Nation. Units 1, 2 and 3 have an accredited capacity of 560 megawatts. These units are 100% owned and operated by APS. Units 4 and 5 have an accredited capacity of 1,480 megawatts; APS owns 15% of units 4 and 5, or 222 megawatts. The remaining interests in units 4 and 5 are co-owned by five other entities. Ownership of units 4 and 5 is through a co-tenancy arrangement, and the co-owners are not affiliates of one another. APS operates Four Corners units 4 and 5 pursuant to an agreement in which each owner pays its proportionate share of the operating cost.

Cholla Power Plant ("Cholla"):

Cholla is a four-unit coal-fired power plant located in Navajo County approximately 200 miles northeast of Phoenix, Arizona. Units 1, 2 and 3 have an accredited capacity of 615 megawatts. These units are 100% owned and operated by APS. Unit 4 has an accredited capacity of 380 megawatts; unit 4 is 100% owned by another unaffiliated entity. APS is also the operator for this unit.

Navajo Power Plant ("Navajo"):

Navajo is a three-unit coal-fired plant located south of Page, Arizona. The total accredited capacity for the plant is 2,250 megawatts. APS owns 14%, or 315 megawatts of this plant. The remaining interests in the plant are co-owned by five other entities which are not affiliated with APS. APS does not operate Navajo.

Saguaro Power Plant ("Saguaro"):

Saguaro is a four-unit power plant consisting of two gas/oil-fired steam units and two gas/oil-fired combustion turbine units and is located 30 miles north of Tucson, Arizona. The total accredited capacity for the plant is 319 megawatts. Steam units 1 and 2 have a combined capacity of 209 megawatts, and the two combustion turbines have a combined capacity of 110 megawatts. This plant is 100% owned and operated by APS.

Ocotillo Power Plant ("Ocotillo"):

Ocotillo is a six-unit multi-fueled generating plant located in Tempe, Arizona. Two units are gas/oil-fired steam units; two units are gas/oil-fired combustion turbines; and two units are solar. The total accredited capacity for steam units 1 and 2 is 226 megawatts; for combustion turbine units 1 and 2, the accredited capacity is 110 megawatts; and for solar units 1 and 2, the accredited capacity is 172 kilowatts. This plant is 100% owned and operated by APS.

Yucca Power Plant ("Yucca"):

Yucca is a five-unit gas/oil combustion turbine plant located near Yuma, Arizona. The accredited capacity of units 1, 2, 3 and 4 is 147 megawatts. These units are 100% owned and operated by APS. Unit 5 and a separate steam unit are owned by a separate, unaffiliated entity but operated by APS.

West Phoenix Power Plant ("West Phoenix"):

West Phoenix is a six-unit gas/oil-fired steam, combustion turbine, and combined cycle generation plant located in Phoenix, Arizona. Combustion turbine units 1 and 2 have an accredited capacity of 110 megawatts; combined cycle units 1, 2 and 3 have an accredited capacity of 255 megawatts; and steam units 4, 5 and 6 have an accredited capacity of 108.3 megawatts. APS owns or leases and operates 100% of West Phoenix and is entitled to 100% of the output.[2]

Douglas/Fairview Power Plant:

Douglas/Fairview is a single combustion turbine unit with a capacity rating of 16 megawatts located near Douglas, Arizona. Douglas/Fairview is 100% owned and operated by APS.

Solar Power Plants

APS also owns a number of solar units that will be moved to PWE as part of the Reorganization. These solar units are located around the state (primarily in the Phoenix metropolitan area) and have a total combined capacity rating of 1 megawatt.

b. ***Power Marketing*** -- APS' Power Marketing and Trading division ("Power Marketing") primarily engages in the sale and purchase of electric capacity and energy in the wholesale market. Power Marketing sells excess power from APS' generation facilities and also purchases energy from other entities to meet APS' requirements to supply retail and wholesale customers. Power Marketing also engages in hedging transactions in forward markets for electricity and fuel and in the purchase and sale of emission allowances as part of APS' effort to manage risks associated with its generation and distribution activities. The ACC Competition

Rules and Settlement contemplate that as a competitive asset, APS will also move its Power Marketing division to an affiliate. Thus, on or before January 1, 2001, Power Marketing will become a division of PNW.[3]

c. ***Transmission/Distribution*** -- APS owns and operates approximately 5,296 miles of transmission lines, of which all but 140 miles are located within the State of Arizona. APS' transmission was built primarily to bring generation from its power plants to its retail electric loads in Arizona. Ownership and operation of APS' transmission facilities is subject to regulation by FERC. Transmission rates are prescribed by FERC and the use of and access to the transmission system is subject to FERC's open access requirements set forth in FERC Order No. 888. As of December 31, 1999, APS' distribution system served approximately 827,000 electric retail customers in its service territory within the State of Arizona. APS provides distribution services in 11 of Arizona's 15 counties, including the metropolitan Phoenix area. Pursuant to the Settlement approved by the ACC in 1999, which is more fully discussed below, retail rates have been set until July 1, 2004, subject to conditions or circumstances which constitute an emergency. APS' transmission and distribution business will remain with APS under the Reorganization.

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[2] APS currently leases its interest in combined cycle units 1, 2, and 3. Because the lease does not expire until June 24, 2001, APS may not move its interest in those units to PWE until mid-2001.

[3] PNW itself will not become an electric utility company when this occurs. The Commission and Staff have both recognized, on numerous occasions, that marketing activities are not utility activities under the Act. See, e.g., UNITIL, Holding Company Act Release No. 26650 (Jan. 21, 1997); SEI Holdings, Inc., Holding Company Act Release No. 26581 (Sept. 26, 1996); Sunoco Power Marketing, L.L.C., SEC No-Action Letter, 1997 SEC No-Act. LEXIS 785 (July 24, 1997); Enron Capital & Trade Resources Corp., SEC No-Action Letter, 1997 SEC No-Act. LEXIS 287 (Feb. 13, 1997); Eastex Power Marketing, Inc., SEC No-Action Letter, 1996 SEC No-Act. LEXIS 536 (Apr. 30, 1996); LG&E Power Marketing, Inc., SEC No-Action Letter, 1996 SEC No-Act. LEXIS 510 (Apr. 26, 1996); Coral Power, L.L.C., SEC No-Action Letter, 1996 SEC No-Act. LEXIS 314 (Feb. 22, 1996); AIG Trading Corp., SEC No-Action Letter, 1995 SEC No-Act. LEXIS 195 (Jan. 20, 1995); Inter-Coast Power Marketing Co., SEC No-Action Letter, 1994 SEC No-Act. LEXIS 886 (Dec. 6, 1994); Electric Clearinghouse, Inc., SEC No-Action Letter, 1994; SEC No-Act. LEXIS 452 (Apr. 13, 1994); CRSS Power Marketing, Inc., SEC No-Action Letter, 1994 SEC No-Act. LEXIS 431 (Mar. 31, 1994).

3. **Pinnacle West Energy Corporation:** PWE was incorporated in Arizona on September 27, 1999 under the laws of the State of Arizona. PWE is a wholly-owned subsidiary of PNW. PWE was organized primarily to engage in the business of developing, owning, and operating generation plants used for the production and sale of wholesale energy. Currently, PWE is engaged in the development of approximately 2,600 megawatts of generating capacity in the State of Arizona and operations in other states are contemplated, too; however, PWE is not currently an electric utility company or a public-utility company within the meaning of the Act. Upon consummation of the Reorganization described herein and the subsequent relocation of APS' nuclear generating facilities, PWE will own or lease the generation facilities currently owned or leased by APS and will assume APS' responsibilities as operator of the facilities described above, with the exception of the Navajo Generating Station, which will continue to be operated by another, unaffiliated entity.[4] PWE's principal place of business is 400 North Fifth Street, Phoenix, Arizona 85004.

4. **APS Energy Services Company, Inc. ("APSES"):** APSES is an Arizona corporation formed in 1998. APSES is a wholly-owned subsidiary of PNW. APSES was organized as a retail power marketer to provide retail energy and related retail energy services to customers throughout Arizona, California, and other states that have instituted retail direct access. APSES does not own or control electric power generation, transmission, or distribution facilities.[5] APSES' principal place of business is 400 East Van Buren Street, Phoenix, Arizona.

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[4] In the future, PWE may also acquire or develop other generating assets. To the extent necessary for PNW to maintain its intrastate exemption, PWE may establish exempt wholesale generator ("EWG") subsidiaries to own and/or operate future assets that may be located out of state.

[5] APSES is not an "electric utility company" or a "public-utility company" as those terms are defined in the Act. See, e.g., Enron, SEC No-Action Letter (1997).

5. **SunCor Development Company ("SunCor"):** SunCor was incorporated in 1965 under the laws of the State of Arizona. SunCor is a wholly-owned subsidiary of PNW. SunCor is engaged in commercial and residential real estate development. SunCor is not engaged in the generating, transmitting, distributing or selling of electric energy and will not be affected by the Reorganization. SunCor's principal place of business is 3838 North Central, Suite 1500, Phoenix, Arizona 85012

6. **El Dorado Investment Company ("El Dorado"):** El Dorado was incorporated in 1983 under the laws of the State of Arizona. El Dorado is an investment company and wholly-owned subsidiary of PNW. El Dorado is not engaged in the business of generating, transmitting, distributing, or selling of electric energy and will not be affected by the Reorganization. El Dorado's principal place of business is 400 East Van Buren Street, Suite 800, Phoenix, Arizona 85004

B. Regulatory Background

The Reorganization is being undertaken in accordance with the Competition Rules and Settlement. Specifically, in Arizona, the ACC has adopted the Competition Rules to expedite the transition to retail electric competition. Among other things, the Competition Rules required that APS separate its generation assets and competitive business activities from its transmission and distribution functions. In 1999, the ACC approved the Settlement between APS and several customer groups and consumer advocates resolving retail electric competition-related issues and approving unbundled tariffs.[6] Under the terms of the Competition Rules and the Settlement, retail choice for APS' retail customers is being phased-in. All of APS' retail customers will be entitled to choose their retail power supplier beginning January 1, 2001.[7] The retail rates of customers that continue to take fully bundled service from APS and do not choose an alternative

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6 The ACC order approving the Settlement is attached as Exhibit D-4.

7 See Exhibit D-4.

supplier will be subject to planned rate reductions that will continue until July, 2004.[8] Under the Settlement, APS is entitled to apply for a change in the agreed upon rate reductions only in the event of an emergency or a material change in its cost of service as a result of specified extraordinary events. The Settlement also requires APS to complete separation of its generation assets by December 31, 2002.[9]

C. The Reorganization

PNW and APS propose to undertake the Reorganization pursuant to the arrangements described in the Term Sheet, attached as Exhibit B-1 hereto.

The principal transactions associated with the Reorganization are described below. As previously mentioned, APS and PWE are both currently direct, wholly-owned subsidiaries of PNW. APS and PWE will be the only two "public-utility company" (as defined in the Act) subsidiaries of PNW upon the completion of the Reorganization. It is contemplated that the following transactions will occur on or before January 1, 2001: First, APS will contribute the bulk of its fossil and solar generating facilities, assets and related operational agreements to one or more of these newly-formed subsidiaries (hereafter "Transitory Subsidiaries") which will be wholly-owned by APS. This transaction is intended to qualify as a tax-deferred reorganization under Internal Revenue Code ("IRC") Section 368(a)(1)(D). Second, APS will distribute or cause to be distributed all of the stock of each Transitory Subsidiary to PNW in a transaction intended to qualify as a tax-deferred spin-off under IRC Section 355. Third, under state law, the Transitory Subsidiaries will then be merged into PWE (with PWE as the surviving entity) in a transaction intended to qualify as a tax-deferred statutory merger under IRC Section 368(a)(1)(A). It is contemplated that the three aforementioned transactions will occur simultaneously.

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[8] See Exhibit D-4.

[9] See Exhibit D-4.

When the Reorganization is complete, APS' existing divisional structure in which its electric utility operations are divided along functional lines will be formalized, and separate corporate entities will engage in the transmission/distribution of electricity and the generation of electricity. APS will become a "wires" company and continue to own and operate its existing electric transmission/distribution system, and PWE will become a "generating" company and will own or lease and operate APS' existing generation assets and sell the output from these assets at wholesale to Power Marketing. Power Marketing, in turn, is expected then to sell power to APS and other non-affiliated power purchasers. APS will continue to provide transmission and distribution services at regulated rates, as well as provide energy to those retail customers in APS' existing service territory that do not elect to use an alternate retail power supplier. A diagram of PNW's corporate structure, after the Reorganization is complete and the nuclear generating facilities have been moved to PWE, is shown on Appendix B to Exhibit D-1 attached hereto.

Consummation of the Reorganization is subject to certain conditions as stated in the Term Sheet attached as Exhibit B-1. Principally, these conditions include: (a) the approval of the Commission under Section 9(a)(2) of the Act; (b) approvals of FERC under Sections 203 and 205 of the Federal Power Act 16 U.S.C. §§824b and d (1994); and (c) consents and waivers of certain third parties with respect to contracts associated with the generation assets. The approval of the ACC has already been granted. [10] No PNW shareholder approval is required in connection with the Reorganization. Although APS does not believe that shareholder approval is required for the Reorganization, the approval of its sole shareholder is expected to be

[10] Approval from the Nuclear Regulatory Commission ("NRC") will be obtained in connection with the movement of APS' interest in its nuclear generating assets, which will occur by year-end 2002. No NRC approval, however, is necessary in connection with the Reorganization involving APS' non-nuclear generating facilities. Approval of some plant participants may also be required.

obtained.[11] The approval of APS' Board of Directors is expected to be obtained in November 2000.

D. Purpose and Anticipated Effects of the Reorganization

The principal purpose of the Reorganization and the subsequent relocation of APS' nuclear generating facilities to PWE is to assure compliance with the provisions of the Competition Rules and the Settlement and provide PNW with increased financial, managerial, and organizational flexibility which will enable APS and PWE to effectively compete in a restructured utility industry. After extensive investigation and analysis, PNW has determined that the proposed Reorganization offers the best means of positioning the PNW system for future changes and opportunities and will enable PNW to take advantage of emerging business opportunities and manage risks to the benefit of both shareholders and customers. The Reorganization is the first step in a clear functional and corporate separation between PNW's competitive generation business, and its distribution and transmission business, enabling each company to focus its resources on more clearly defined product markets and services. The intent of the Reorganization and subsequent relocation of APS' nuclear generating facilities is to create a financially sound and responsive utility system which can provide utility services effectively and efficiently. Additionally, the corporate division along functional lines will provide a better structure for regulators to assure that there is no cross-subsidization of costs or transfer of business risk from the competitive generation business to the fully-regulated transmission/distribution business. Moreover, this type of corporate division of utility operations along functional lines is becoming a highly-desirable form of conducting both a regulated transmission/distribution business and a competitive generation business.

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[11] As a wholly-owned subsidiary of PNW, APS' only shareholder is PNW.

The Reorganization will have no adverse effect on APS' existing electric utility operations. The Reorganization will not cause substantive changes in PNW's ultimate interest in existing utility businesses and will not involve the transfer or acquisition of any additional utility assets beyond those currently held by APS or those which may be developed or acquired by PWE in the future. The managers and employees in PNW's existing utility operations will continue to perform their existing functions -- either as employees of APS, the transmission/distribution company, or as employees of PWE, the generating company. Thus, even though day-to-day utility operations would not be affected, the benefits discussed above will accrue to PNW and its customers and shareholders as a result of the Reorganization and the subsequent relocation of APS' nuclear generating facilities to PWE.

E. Additional Information

No associate company or affiliate of PNW or APS, or any affiliate of any associate company of PNW or APS, has any direct or indirect material interest in the proposed Reorganization except as stated herein.

ITEM 2 FEES, COMMISSIONS AND EXPENSES

The fees, commission and expenses to be paid or incurred by PNW and APS in connection with the Reorganization are estimated as follows:

Auditors' Fee	*
Legal Fees	*
Miscellaneous	*
Total	*

* To be filed by amendment

ITEM 3 APPLICABLE STATUTORY PROVISIONS

Sections 9(a)(2) and 10 of the Act are applicable to the proposed Reorganization. As a result of the proposed Reorganization, PNW will have two wholly-owned, public-utility company subsidiaries, APS and PWE. Section 9(a)(2) of the Act requires Commission approval before a person may acquire more than 5% of the outstanding voting securities of more than one "public-utility company." The standards for approval of a transaction under Section 9(a)(2) of the Act are set forth in Section 10 of the Act. The relevant standards under Section 10 are set forth in Section 10(b), 10(c) and 10(f).

For the reasons explained below, the Commission should approve the Reorganization pursuant to Section 9(a)(2) of the Act because it complies with the applicable standards of Section 10. PNW respectfully requests that the Commission issue an order approving the Reorganization by December 1, 2000, so that PNW has sufficient time to complete the Reorganization on or before January 1, 2001.[12] PNW anticipates moving most of the assets and personnel on or before January 1, 2001 ,[13] in order to facilitate calendar year record keeping, and believes that the time between the requested approval date of December 1, 2000, and the contemplated Reorganization is necessary to allow the transfer of personnel and to implement other aspects of the Reorganization.

A. Approval of the Reorganization under Section 9(a)(2).

Section 9(a)(2) makes it unlawful, without approval of the Commission under Section 10, "for any person . . . to acquire, directly or indirectly, any security of any public-utility company, if such person is an affiliate . . . of such company and of any other public utility or holding

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[12] In the event the Commission does not issue its order by December 1, 2000, PWE intends to file an application with FERC for EWG status and limit its activities exclusively to the ownership and operation of eligible facilities and sale of power at wholesale in order to maintain EWG status until the Commission issues an order approving the Reorganization.

company, or will by virtue of such acquisition become such an affiliate." By virtue of the proposed Reorganization, PNW will own more than 5% of the outstanding voting securities of two "public-utility companies" (APS and PWE) thus becoming an affiliate of both of these public-utility companies. Under Section 2(a)(5) of the Act, a "public-utility company" is an "electric utility company" or a "gas utility company." Under Sections 2(a)(3) and 2(a)(4) of the Act, an "electric utility company" is defined as "any company which owns or operates facilities used for the generation, transmission, or distribution of electric energy for sale . . . ." Upon completion of the Reorganization, PWE will own and operate certain of APS' existing facilities for the generation of electric energy for sale, and APS will continue to own and operate its existing facilities for the transmission and distribution of electric energy for sale, as well as its nuclear generating facilities. Therefore, both PWE and APS will be public-utility companies within the meaning of the Act.

1. Section 10(b)

Section 10(b) provides that the Commission shall approve an acquisition pursuant to Section 9(a)(2) unless the Commission finds that:

(1) such acquisition will tend towards interlocking relations or the concentration of control of public-utility companies, of a kind or to an extent detrimental to the public interest or the interest of investors, or consumers;

(2) in case of the acquisition of securities or utility assets, the consideration, including all fees, commissions, and other remuneration, to whomsoever paid, to be given, directly or indirectly, in connection with such acquisition is not reasonable or does not bear a fair relation to the sums invested in or the earning capacity of the utility

[13] As noted above, certain generating assets, such as PVNGS and combined cycle units 1, 2, and 3 at West Phoenix, may be moved to PWE at a later date.

assets to be acquired or the utility assets underlying the securities to be acquired; or

(3) such acquisition will unduly complicate the capital structure of the holding-company system of the applicant or will be detrimental to the public interest or the interest of investors or consumers or the proper functioning of such holding-company system.

PNW respectfully submits that no adverse findings should be made under any of these provisions.

a. "Detrimental Interlocking Relations" or "Concentration of Control" -- Section 10(b)(1)

Consistent with Section 10(b)(1) of the Act, PNW submits that the Reorganization will not tend towards interlocking relations or the concentration of control of public-utility companies, of a kind or to an extent detrimental to the public interest or the interest of investors or customers. The Reorganization involves the first step in the ultimate segregation of APS' existing utility assets and operations along functional lines into a generation company (PWE) and a transmission and distribution company (APS).

While there may be certain common directors and officers of PNW and the public-utility subsidiaries, these relations normally exist in public-utility holding company systems among affiliated and associated companies and should not be considered detrimental to the public interest or the interest of investors or consumers. See Central Maine Power Company, et al., Holding Co. Act Release No. 26903 (Aug. 7, 1998); CIPSCO, Inc., Holding Co. Act Release No. 25152, 47 SEC Docket 174 (Sept. 18, 1990).

Similarly, the Reorganization should not, within the meaning of Section 10(b)(1), be deemed to tend towards any "concentration of control of public-utility companies" that might be detrimental to the public interest, consumers or investors. The Reorganization will not involve

the acquisition or control of any utility assets or operations which are not already owned or controlled by PNW or its existing public-utility subsidiary, APS, or being developed by PWE, and "will therefore have no effect on the concentration of control of public-utility companies." Central Maine Power Company, et al., Holding Co. Act Release No. 26903 (Aug. 7, 1998); accord BEC Energy, et al., Holding Co. Act Release No. 26874 (May 15, 1998); Energy East Corp., Holding Co. Act Release No. 26834 (March 4, 1998); Wisconsin Energy Corp., Holding Co. Act Release No. 24267 (Dec. 18, 1996).

b. Fairness of Consideration and Fees -- Section 10(b)(2)

Section 10(b)(2) of the Act requires the Commission to determine whether the consideration paid in connection with a proposed acquisition of securities is reasonable and bears a fair relation to the investment in and earning capacity of the utility assets underlying the securities being acquired.

The generating assets will be recorded on the books of PWE at net book value. In addition, PWE will assume certain outstanding debt associated with the generating assets being moved. The valuation of PNW's investment in the securities of PWE and APS will be adjusted accordingly to reflect the movement of these assets and the associated debt to PWE. [14]

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[14] Specifically, PWE will assume APS' rights and obligations with respect to approximately $180 million in pollution control bonds issued by Navajo County, Arizona, Pollution Control Corporation and Coconino County, Arizona, Pollution Control Corporation. These two series of bonds were issued by the respective pollution control corporations under two separate Indentures of Trust dated as of August 1, 1993 between the issuer and an independent trustee. In each case, the issuer loaned the proceeds of the bonds to APS under a Loan Agreement dated as of August 1, 1993, and APS is responsible to repay the loan by making payments on the bonds when due. APS' obligations are secured by First Mortgage Bonds issued by APS and delivered to the Trustee for the pollution control bonds. At the time generating assets are moved to PWE, APS will assign its rights and obligations under the Loan Agreements to PWE, and PWE will assume such obligations. APS will remain primarily liable for such obligations and the First Mortgage Bonds will remain outstanding.

PWE will also assume APS' obligations under another approximately $60 million of pollution control bond debt, releasing APS from such obligations. No bondholder consent is required in connection with PWE's assumption of this debt. However, APS must give advance notice to the bondholders and any bondholder who does not wish to continue to hold the bonds may tender its bonds for purchase. In addition, if the issuance of a new letter of credit in substitution for the existing letter of credit supporting the bonds causes the ratings on the bonds to be lower than the existing rating, the bonds will be subject to a mandatory tender on the substitution date, and all the bonds will be subject to mandatory repurchase and remarketing on that date.

Since the Reorganization involves an entirely intra-company movement of existing assets from one wholly-owned subsidiary to another and not the acquisition of new assets or securities, PNW believes that the valuation established for purposes of this asset transition is reasonable and bears a fair relationship to the sums invested in the assets. PNW, as the sole owner of both APS and PWE, can expect to earn a fair return on its investment in APS and its investment in PWE.

An estimate of the fees and expenses to be paid in connection with the Reorganization is stated in Item 2 above. Such fees and expenses will be reasonable and customary for a transaction of this kind and will not be material when measured against PNW's consolidated book value or the earning capacity of its assets. See, e.g., Energy East Corp., Holding Co. Act Release No. 27128 (Feb. 2, 2000).

c. Complication of Capital Structure -- Section 10(b)(3)

Section 10(b)(3) of the Act requires the Commission to determine whether the transaction will unduly complicate the capital structure of the PNW system, be detrimental to the public interest, the interest of the investors or consumers, or the proper functioning of the holding-company system. No such effect will result from the Reorganization.

The Reorganization will not involve the creation of any ownership interests other than those necessary to maintain the basic corporate relationships of the reorganized holding-company system. Pursuant to the Reorganization, PNW will continue to be the only issuer of publicly owned equity securities in the system. PNW will continue to own all of the outstanding common stock of PWE, APS, and PNW's existing non-utility subsidiaries; there will be no minority equity interest in any of PNW's public-utility subsidiaries. As noted above, certain pollution control bonds issued by APS will be assumed by PWE, but this will in no way complicate the capital structure of PNW, APS, or PWE. This type of capital structure is typical of a contemporary holding company system and is within the traditional standards of the Act.

Moreover, the Reorganization is a significant step toward the ultimate goal of creating separate entities to perform PNW's transmission/distribution business and its generation business in compliance with the ACC's Competition Rules and the Settlement. Consequently, because the Reorganization does not complicate the capital structure of PNW, APS, or PWE, the standards of Section 10(b)(3) of the Act are satisfied.

2. Section 10(c)

The relevant provisions of Section 10(c) of the Act state that the Commission shall not approve:

> (1) an acquisition of securities or utility assets, or of any other interest, which is unlawful under the provisions of Section 8 or is detrimental to the carrying out of the provisions of Section 11; or

(2) the acquisition of securities or utility assets of a public-utility or holding company unless the Commission finds that such acquisition will serve the public interest by tending towards the economical and the efficient development of an integrated public-utility system . . . .

APS and PNW respectfully submit that no adverse determination should be made under either of these provisions.

a. Significant Benefits -- Section 10(c)(1)

Section 10(c)(1) prohibits an acquisition of securities which is "unlawful under the provisions of Section 8" or "detrimental to the carrying out of the provisions of Section 11." By their express terms, Sections 8 and 11 apply only to registered holding companies and do not apply to exempt holding companies. After the Reorganization, PNW will continue to be exempt from all provisions of the Act, except Section 9(a)(2), pursuant to Section 3(a)(1) of the Act since PNW and its utility subsidiaries, APS and PWE, will each be predominantly intrastate in character, carry on their businesses substantially in Arizona, and be organized in Arizona. Accordingly, Section 8 of the Act is inapplicable to the Reorganization.

For the purposes of the Commission's review of the proposed reorganization of a holding company, the relevant provision of Section 11 is Section 11(b)(2), which requires the Commission to find that "the corporate structure . . . of any company in the holding-company system does not unduly or unnecessarily complicate the structure . . . of such holding-company system." In that connection, the Commission has construed this requirement, "to mean that the structural change must result in significant benefits to the holding-company system." CIPSCO Inc., Holding Co. Act Release No. 25152, 47 SEC Docket at 178 (Sept. 18, 1990); accord Central Maine Power Company, et al., Holding Co. Act Release No. 26903 (Aug. 7, 1998); BEC Energy, et al., Holding Co. Act Release No. 26874 (May 15, 1998); Energy East Corp., Holding Co. Act Release No. 26834 (March 4, 1998).

As discussed above in Section D of Item 1, the corporate structure resulting from the Reorganization will yield significant benefits. Most importantly, the Reorganization and subsequent move of APS' nuclear generating facilities to PWE will enable APS to implement the requirements of ACC Competition Rules and Settlement. In addition, segregation of the separate

utility functions into separate corporations dedicated solely to those functions will: (1) enable the executives, officers, and managers of APS and PWE to concentrate on the delivery of cost efficient and effective utility services responsive to the needs of customers; (2) allow PNW's subsidiaries and affiliates to be more competitive in their businesses; (3) segregate the financial and legal risks associated with those businesses; (4) ensure that there is no cross-subsidization of costs or business risk; and (5) aid the investment community in analyzing and valuing individual lines of business. In cases involving corporate reorganizations or the formation of holding companies, the Commission has held that the existence of these kinds of potential benefits satisfies the statutory standard of Section 10(c)(1). See, e.g., Central Maine Power Company, Holding Co. Act Release No. 26903 (Aug. 7, 1998); Atlanta Gas Light Company, Holding Co. Act Release No. 26482, 61 SEC Docket 1057 (March 5, 1996); SIGCORP, Inc., Holding Co. Act Release No. 26431, 60 SEC Docket 90 (Dec. 14, 1995); PP&L Resources, Inc., Holding Co. Act Release No. 26248, 58 SEC Docket 2634 (March 10, 1995); CIPSCO Inc., Holding Co. Act Release No. 25152, 47 SEC Docket 174 (Sept. 18, 1990); Wisconsin Energy Corp., Holding Co. Act Release No. 24267 (Dec. 18, 1996).

b. Economics and Efficiencies of an Integrated System – Section 10(c)(2)

Under Section 10(c)(2), the Commission must find that the Reorganization tends towards the economical and efficient development of an integrated public utility system. PNW respectfully submits that this standard is met in this case.

(i) Economics and Efficiencies

A number of economies and efficiencies will result from the PNW structure. Some of these benefits are described in Section D of Item 1 and Section A.2.a of Item 3, above. Overall, the Reorganization will permit a more efficient way to take advantage of competitive opportunities in the electric utility industry. Separating the competitive generation business from the regulated transmission/distribution operations will increase the ability of the system to take advantage of market opportunities and enable each entity to focus its resources on more clearly defined product markets and services.

(ii) Integrated Public Utility System

The electric utility system of PNW is presently "integrated" within the meaning of Section 2(a)(29) of the Act and will remain so after the Reorganization.

The standards that must be met for an electric utility system to be integrated within the meaning of Section 2(a)(29) of the Act are:

(1) the utility assets are to be physically interconnected or capable of physical interconnection and under normal conditions may be economically operated as a single interconnected and coordinated system;

(2) the operations of the system are confined to a single area or region, that is not so large as to impair the advantages of localized management, efficient operation, and the effectiveness of regulation.

The Reorganization will not affect the physical interconnections associated with PNW's existing utility system. All of APS' existing interconnections will remain intact after the Reorganization. The Reorganization will maintain a continuous, geographically compact system with the same physical interconnections as exist today. Similarly, the area of operations of the system will not be affected by the Reorganization and will continue to be primarily confined to a single area (e.g., APS' existing service territory in Arizona) that is not so large as to impair the advantages of

continuing localized management, efficient operation, and effective regulation. See CP&L Energy, Inc., Holding Co. Act Release No. 27188 (June 15, 2000); Central Maine Power Company, et al., Holding Co. Act Release No. 26903 (Aug. 7, 1998).

3. Section 10(f)

Section 10(f) provides that "[t]he Commission shall not approve any acquisition . . . under this Section unless it appears to the satisfaction of the Commission that such State laws as may apply in respect of such acquisition have been complied with, except where the Commission finds that compliance with such State laws would be detrimental to the carrying out of the provisions of Section 11 . . . ."

The Reorganization is conditioned on full compliance with the laws of the Arizona. APS is currently and will remain subject to the jurisdiction of the ACC with respect to the provision of retail electric service. APS and PNW have received the necessary approval from the ACC to proceed with the Reorganization. Copies of this ACC approval is filed as Exhibit D-5 hereto.

For the reasons stated above, the proposed Reorganization meets the standards set forth in Sections 9(a)(2) and 10. The Reorganization involves the first step in the segregation of APS' existing utility assets and operations along functional lines into a wires company and a generation company. The Reorganization will not unduly complicate the capital structure of the PNW system; nor will the Reorganization be detrimental to the public interest, the interests of investors or consumers, or the proper functioning of this system. Also, the Reorganization will yield significant benefits by allowing PNW's public-utility subsidiaries to more effectively compete in the electric utility industry. Therefore, the Commission should by order approve the Reorganization.

B. PNW Will Continue to Claim a Section 3(a)(1) Exemption After the Reorganization.

Section 3(a)(1) of the Act makes an exemption from all of the provisions of the Act, except for Section 9(a)(2), available to a holding company, if "such holding company, and every subsidiary company thereof which is a public-utility company from which such holding company derives, directly or indirectly, any material part of its income, are predominately intrastate in character and carry on their business substantially in a single State in which such holding company and every such subsidiary company thereof are organized." After the Reorganization is complete, PNW and its two public-utility subsidiaries -- APS and PWE -- will be predominantly intrastate in character and will carry on their business substantially in Arizona, the state in which they are all organized.[15] In this regard, PNW will continue to claim an exemption pursuant to Section 3(a)(1) of the Act and Rule 2 of the Commission's regulations, by filing annual exemption statements on Form U-3A-2 following the Reorganization.

ITEM 4 REGULATORY APPROVAL

The Reorganization will require the approval of the ACC and FERC. APS has received an order approving the Reorganization from the ACC, a copy of which is attached hereto as Exhibit D-5. APS has also filed an application for approval of the proposed Reorganization with the FERC, a copy of which is attached as Exhibit D-1. A copy of the final FERC order pursuant thereto will be filed as Exhibit D-2 by amendment hereto. Other than such enumerated approvals and the approval of the Commission hereunder, no other approvals of utility regulatory authorities are required for the Reorganization and the movement of the non-nuclear generating assets to PWE.

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[15] While APS' existing power marketing division will be moved to PNW, and will continue to perform its power marketing activities on a nationwide basis, PNW's utility operations will still be predominately intrastate in character and conducted primarily in Arizona. As noted above, the Commission Staff has indicated in a series of no-action letters that power marketers are not considered "electric utility companies" under Section 2(a)(3) of the Act and, therefore, are not "public-utility companies" under Section 2(a)(5) of the Act. See, e.g., Sunoco Power Marketing, L.L.C., SEC No-Action Letter, 1997 SEC No-Act. LEXIS 785 (July 24, 1997); Enron Capital & Trade Resources Corp., SEC No-Action Letter, 1997 SEC No-Act. LEXIS 287 (Feb. 13, 1997).

ITEM 5 PROCEDURE

PNW respectfully requests that there be no 30-day waiting period between the issuance of the Commission's order and the date on which it is to become effective. PNW also requests that there be no hearing on this application and that the Commission issue its order as soon as practicable after the filing hereof. PNW respectfully requests that the Commission issue and publish the requisite notice under Rule 23 with respect to the filing of this application not later than October 12, 2000, such notice to specify a date not later than November 13, 2000, by which comments may be entered and a date not later than December 1, 2000, as the date after which an order of the Commission granting and permitting this application to become effective may be entered by the Commission. A form of Notice is filed herewith as Exhibit H-1.

Without prejudice to its right to modify the same if a hearing should be ordered on this application, PNW hereby makes the following specifications required by paragraph (b) of Item 5 of Form U-1:

(1) There should not be a recommended decision by a hearing officer or any other responsible officer of the Commission.

(2) There should not be a 30-day waiting period between issuance of the Commission's order and the date on which the order is to become effective.

(3) PNW consents to the Division of Investment Management assisting in the preparation of the Commission's decision or order in this matter, unless such Division opposes this application.

ITEM 6 EXHIBITS AND FINANCIAL STATEMENTS

It is requested that the Commission send copies of all communications to PNW as follows:

Herbert I. Zinn
Pinnacle West Capital Corporation
400 North Fifth Street
Mail Station 8695
Phoenix, Arizona 85004

Mary Ann K. Huntington
Morgan, Lewis & Bockius LLP
1800 M Street, N.W.
Washington, D.C. 20036

A. **Exhibits**

Exhibit No.	Description of Document	Method of Filing
A-1	Restated Articles of Incorporation of PNW.	Incorporated by reference; File No. 1-8962, PNW Form 10-K for the year ended December 31, 1999.
A-2	Restated Articles of Incorporation of APS.	Incorporated by reference; File No. 1-4473, APS Form 8-K (Sept. 23, 1993)
A-3	Articles of Incorporation of PWE.	Filed herewith.
B-1	Form of Term Sheet	Filed herewith.
D-1	Application of APS, PNW and PWE to FERC for Authorization to Transfer Jurisdictional Facilities.	Filed herewith.
D-2	Order of FERC.	To be filed by amendment.
D-3	Retail Electric Competition Rules	Incorporated by reference; file No. 1-4473, filed as Exhibit 10.2 to APS' Sept. 30, 1999 Form 10-Q Report.

D-4	Comprehensive Settlement Agreement Related to the Implementation of Retail Electric Competition, filed with the Arizona Corporation Commission.	Incorporated by reference; File No. 1-4473, filed as Exhibit 10.1 to APS' May 14, 1999 Form 8-K Report.
D-5	ACC Approval of the Settlement Agreement.	Incorporated by reference; File No. 1-4473, filed as Exhibit 10.1 to APS' Sept. 1999 10-Q Report.
D-6	Amended Settlement Agreement	Filed herewith.
E-1	Map showing location of the generating facilities of APS that are being moved to PWE along with their related transmission facilities.	Filed herewith.
F-1	Signed initial opinion of counsel.	To be filed by amendment.
F-2	Past-tense opinion of counsel.	To be filed by amendment.
G-1	PNW, Form U-3A-2, "Statement by Holding Company Claiming Exemption under Rule U-2 from the Provisions of the Public Utility Holding Company Act of 1935."	Incorporated by reference; File No. 69-306, dated Feb. 29, 2000.
H-1	Form of Notice	Filed herewith.

B. Financial Statements

Statement No.	Description of Document	Method of Filing
FS-1	Historical consolidated financial statements of PNW	Incorporated by reference to Annual Reports on Form 10-K for the years ended 1999, 1998 and 1997
FS-2	Historical consolidated financial statements of APS	Incorporated by reference to Annual Reports on Form 10-K for the years ended 1999, 1998 and 1997

Although separate financial statements for PWE have not been included, PWE's financial information is included in the consolidated financial statements of PNW.

ITEM 7 INFORMATION AS TO ENVIRONMENTAL EFFECTS

None of the matters that are the subject of this application and declaration involves a "major federal action" nor do any of them "significantly affect the quality of the human environment" as those terms are used in Section 102(2)(C) of the National Environmental Policy Act. The transaction that is the subject of this application will not result in changes in the operation of the company that will have an impact on the environment. Neither APS nor PNW are aware of any federal agency that has prepared or is preparing an environmental impact statement with respect to the transactions that are the subject of this application.

SIGNATURE

Pursuant to the requirements of the Public Utility Holding Company Act of 1935, the undersigned company has duly caused this Application to be signed on its behalf by the undersigned thereunto duly authorized.

PINNACLE WEST CAPITAL CORPORATION

By: Barbara M. Gray
Its: Treasurer

Date: September 12, 2000

Phoenix, Arizona

The transfer will not impair or diminish the Commission's jurisdiction in any respect. The restructuring plan of APS will not materially affect the ability of the Commission or state regulators to assert their regulatory jurisdiction over PWCC and its subsidiaries APS and PWE. After the transfer of assets, the Commission will continue to have jurisdiction over all of the existing wholesale transactions of APS that are being assigned to PWCC and PWE, and PWCC and PWE will be subject to federal regulation with respect to all of their wholesale power transactions. APS will continue to be subject to FERC oversight pertaining to transmission and wholesale power contracts. APS will also continue to be subject to state regulation pertaining to distribution rates and retail sales to standard offer customers under bundled rates. PWE will be under state regulation where the generation plants are located regarding applicable permitting and siting requirements. Finally, PWCC will continue to be an exempt holding company under PUHCA; therefore, the transfer will not result in any transfer of jurisdiction from the Commission to the SEC.

D. Public Interest Conclusion

Given that the proposed restructuring plan will have no adverse effect on competition, rates, or regulation, the Commission should find the plan consistent with the public interest.

V. FILING REQUIREMENTS UNDER PART 33

In accordance with the regulations, 18 C.F.R. § 33.2, Applicant states as follows:

A. Exact name and address of the principal business office of Applicants are:

Arizona Public Service Company
400 North Fifth Street
Phoenix, AZ 85004

Pinnacle West Capital Corporation
400 North Fifth Street
Phoenix, AZ 85004

Pinnacle West Energy Corporation
400 North Fifth Street
Phoenix, AZ 85004

B. Names and addresses of the persons authorized on behalf of Applicants to receive notices and communications in respect to this Application are as follows:

James M. Levine
Executive Vice President Generation
Arizona Public Service Company
400 North 5th Street
Mail Station 9046
Phoenix, Arizona 85004
Phone: (602) 250-2095

Barbara M. Champion
Senior Attorney
Pinnacle West Capital Corporation
400 North 5th Street
Mail Station 8695
Phoenix, Arizona 85004
Phone: (602) 250-3547

Joel R. Spitzkoff
Manager of Federal Regulation
Arizona Public Service Company
400 North 5th Street
Mail Station 9905
Phoenix, Arizona 85004
Phone: (602) 250-2949

John D. McGrane
Mary Ann K. Huntington
Kristina Beard
Morgan, Lewis & Bockius, LLP
1800 M Street, N.W
Washington, D.C. 20036
Phone: (202) 467-7000

C. Designation of the Territories served by Applicants, by counties and states:

APS is an investor-owned utility engaged in the business of generation, transmission, distribution and sale of electricity in all or part of eleven of Arizona's fifteen counties. APS serves numerous wholesale customers with power, and provides various transmission services to wholesale marketers, other utilities, municipalities, Federal power marketing agencies, electric cooperatives, electric districts and irrigation districts within the State of Arizona. Neither PWE nor PWCC has any service territories.

D. General statement briefly describing the facilities owned or operated for transmission of electric energy in interstate commerce or the sale of electric energy at wholesale in interstate commerce:

APS owns and operates generation resources and 4,283 miles of transmission facilities in Arizona and 140 miles of transmission facilities in New Mexico, and distribution facilities throughout much of Arizona. PWE will not possess transmission facilities other than the transmission facilities associated with generation plants that APS proposes to transfer to PWE. PWCC will not have any transmission facilities. Both PWCC and

PWE will have contracts and agreements with other parties that will be jurisdictional.

E. This Application seeks authorization of the Commission to transfer:

As described in Section III of this Application, APS seeks to transfer certain FERC-jurisdictional facilities and operating agreements to PWE, a newly formed affiliate of its parent company, Pinnacle West Capital Corporation. The transfer of assets will be at their book value at the time of transfer. Their current value at the time of filing is $24,514,216 Additionally, APS seeks to transfer to PWCC certain wholesale contracts, APS's Electric Coordination Tariff with all related service agreements, and certain service agreements under its market based tariff.

F. A statement of facilities to be disposed of, consolidated, or merged, giving a description of their present use and of their proposed use after disposition, consolidation or merger. State whether the proposed disposition of facilities or plan for consolidation or merger includes all the operating facilities of the parties of the transaction:

Attachment A contains a list of the jurisdictional transmission facilities that APS is transferring to PWE under this Application. The jurisdictional transmission facilities being transferred are step-up transformers and associated facilities located at or adjacent to the generation plants that APS is also transferring to PWE. As described in Section III of this Application, the transferred facilities will be utilized in the same manner as before the transfer. APS will continue to operate as a "wires" company with transmission and distribution assets.

Attachment B is a list of the contracts and service agreements that APS intends to transfer to PWE and PWCC. APS also seeks permission to transfer additional service agreements to PWCC that it may enter into between the time of this filing and when the actual transfer of contracts is approved.

G. A statement (in the form prescribed by the Commission's Uniform System of Accounts for Public Utilities and Licensees) of the cost of the facilities involved in the sale, lease, or other disposition or merger or consolidation. If original cost is not known, an estimate of original cost based, insofar as possible, upon records or data of the Applicant or its predecessors must be furnished, together with a full explanation of the manner in which such estimate has been made, and a description and statement of the present custody of all existing pertinent data and records:

See Attachment C. The Applicants intend to account for the transfer in accordance with Electric Plant Instruction No. 5 and Account 102 of the

Commission's Uniform System of Accounts. Applicants will file the proposed accounting when they notify the Commission that the transfer is consummated.

H. **A statement as to the effect of the proposed transaction upon any contract for the purchase, sale or interchange of electric energy:**

The transfer of facilities will not have any effect upon the ability of APS, PWCC, or PWE to meet their contractual obligations. The transfer of transmission facilities is ancillary to the generating units being transferred and will not have any material effect on the existing transmission contracts of APS. *See* Section IV. B. on the discussion of how the APS restructuring plan will effect rates.

I. **A statement as to whether any Application with respect to the transaction or any part thereof is required to be filed with any other Federal or state regulatory body:**

The following other regulatory approvals have been or will be obtained to facilitate the transfer of assets:

- The approval of the settlement agreement on October 6, 1999 by the ACC authorized APS to transfer its generating assets to a separate affiliate to foster open retail access (*see* Attachment D). APS intends to inform the ACC at least thirty days before the actual transfer of the assets.

- Approval of the transfer of APS's interest in the Palo Verde Nuclear Generating Facility by the Nuclear Regulatory Commission pursuant to the Atomic Energy Act.

- Further approvals, if necessary, from the Securities and Exchange Commission and the Federal Communications Commission to complete the APS restructuring plan.

J. **The facts relied upon by Applicant to show that the proposed disposition, merger, or consolidation of facilities or acquisition of securities will be consistent with the public interest:**

See Section IV of the Application.

K. **A brief statement of franchises held, showing date of expiration if not perpetual:**

See Attachment E, List of County and Municipal Franchises.

L. A form of notice suitable for publication in the FEDERAL REGISTER, as well as a copy of the same notice in electronic format:

See Attachment F. An electronic version of the notice is included in the filing on a 3 1/2 " diskette, in Wordperfect.

VI. REQUIRED EXHIBITS UNDER PART 33

Exhibits A, C, D, E, and F:

Applicants request a waiver of the requirements to include Exhibits A, C, D, E, and F. Such a waiver is consistent with the Commission's *Notice of Proposed Rulemaking: Revised Filing Requirements Under Part 33 of the Commission's Regulations*, IV FERC Stats. & Regs. ¶ 32,528, at 33,364 (1998), in which the Commission proposed to streamline the filing of the financial and accounting information currently required in Exhibits A, C, D, E, and F. Good cause exists to waive these filing requirements because the information required by these exhibits is not necessary for the Commission to render a decision on this Application. The Commission has recently approved other Applications for corporate realignments similar to this filing without detailed financial information. *See, e. g., Public Service Electric & Gas Co.*, 88 FERC ¶ 61,299 (1999). In accordance with the regulations, 18 C.F.R. § 33.3, Applicants attach the following exhibits to this Application:

Exhibit B: Statement of Measure of Control

The proposed transactions will not create new corporate relationships with third parties. All relevant entities are wholly owned subsidiaries of PWCC, which remains the parent company. A statement describing the measure of control or ownership is attached as Exhibit B.

Exhibit G: Application Filed with Federal and State Regulators

In the event Applicants file their Application with the Nuclear Regulatory Commission ("NRC") for approval to transfer APS's interest in the Palo Verde Nuclear Generating Facility to PWE prior to such time as the Commission has approved the instant Section 203 application, Applicants will submit a copy of the NRC Application to the Commission. Otherwise, Applicants request a waiver from the requirement to file Exhibit G.

Exhibit H: Copy of All Contracts between APS and PWE Regarding the Proposed Transfer of Assets

As this Application is for an affiliate transfer, APS has not entered into any contracts to sell, lease, or otherwise dispose of the jurisdictional facilities that are the subject of this Application.

Exhibit I: Map

A map showing the location of the generation facilities of APS that are being transferred to PWE along with their related transmission facilities is attached as Exhibit I.

VII. PROCEDURAL MATTERS

A. Request for Approval Without Hearing

Applicants respectfully request that the Commission approve the disposition of jurisdictional facilities associated with the restructuring that is occurring in Arizona on an expedited basis and without hearing based on the facts and supporting documents provided in this Application. The Application should support a finding that the transfer of assets is in the public interest and will promote competition.

B. Waiver

To the extent necessary, Applicants request a waiver of the requirement to file a market analysis in accordance with Appendix A of the Merger Policy Statement and any other waiver the Commission deems necessary to approve this Application under Section 203. Given that this filing is required to accommodate restructuring in Arizona, and that there are no rate impacts on existing customers, the Applicants believe good cause is shown for such a waiver.

C. Service and Communication

Applicants have served a copy of this Application on the ACC and the New Mexico Public Regulation Commission. Applicants have also served a copy of the transmittal letter accompanying this filing on all customers under APS wholesale contracts and service agreements that are being transferred to either PWCC or PWE. Applicants will provide any of the above customers with a complete copy of this filing upon request.

Communications regarding this Application should be addressed to the following persons, who are also designated for service in this proceeding:

James M. Levine
Executive Vice President Generation
Arizona Public Service Company
400 North 5th Street
Mail Station 9046
Phoenix, Arizona 85004
Phone: (602) 250-2095

Barbara M. Champion
Senior Attorney
Pinnacle West Capital Corporation
400 North 5th Street
Mail Station 8695
Phoenix, Arizona 85004
Phone: (602) 250-3547

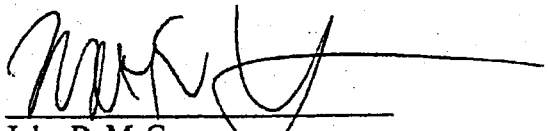
Joel R. Spitzkoff
Manager of Federal Regulation
Arizona Public Service Company
400 North 5th Street
Mail Station 9905
Phoenix, Arizona 85004
Phone: (602) 250-2949

John D. McGrane
Mary Ann K. Huntington
Kristina Beard
Morgan, Lewis & Bockius, LLP
1800 M Street, N.W.
Washington, D.C. 20036
Phone: (202) 467-7000

VIII. CONCLUSION

For the foregoing reasons, Applicants respectfully request the Commission (1) to authorize the transfer of FERC-jurisdictional facilities required to implement APS's restructuring plan as described in this Application, (2) to approve the Application without hearing, and (3) to grant waiver of any filing requirements or other regulations as the Commission may find appropriate to allow approval of the transfer of assets from APS to PWE, directly or indirectly, and the transfer of jurisdictional rates schedules from APS to PWCC and PWE.

Respectfully submitted,



John D. McGrane
Mary Ann K. Huntington
Kristina Beard
Morgan, Lewis & Bockius LLP
1800 M Street, N.W.
Washington, D.C. 20036
Phone: (202) 467-7000

Barbara M. Champion, Senior Attorney
Pinnacle West Capital Corporation
P.O. Box 53999
Mail Station 8695
Phoenix, Arizona 85072-3999
Phone: (602) 250-3547

Attorneys for
Arizona Public Service Company
Pinnacle West Capital Corporation
Pinnacle West Energy Corporation

Dated: July 28, 2000

DEBORAH SCOTT
ARIZONA CORPORATION COMMISSION
1200 WEST WASHINGTON STREET
PHOENIX, AZ 85007

AJO IMPROVEMENT COMPANY
P.O. DRAWER 9.
AJO, AZ 85321

AMERICAN ELECTRIC POWER
1 RIVERSIDE PLAZA
COLUMBUS, OH 43215-2373

AMERICAN HUNTER ENERGY, INC.
1100 LOUISIANA, SUITE 5025
HOUSTON, TX 77002

ARIZONA ELECTRIC POWER COOP.
P.O. BOX 670
BENSON, AZ 85602

BRITISH COLUMBIA POWER EXCHANGE
666 BURRARD STREET, SUITE 1440
VANCOUVER, B.C. V6C 2X8
CANADA

CALIFORNIA POWER EXCHANGE
1000 SOUTH FREEMONT AVE
BLDG A9W - 5TH FLOOR
ALHAMBRA, CA 91803

RESAL CRAVEN
CITIZENS UTILITIES COMPANY
2901 NORTH CENTRAL AVENUE, SUITE 1660
PHOENIX, AZ 85012

TUCSON ELECTRIC POWER CO.
P.O. BOX 711
TUCSON, AZ 85702

CITY OF AZUSA
P.O. BOX 9500
AZUSA, CA 91702

KENNETH R. SALINE, P.E.
K.R. SALINE & ASSOCIATES
160 N. PASADENA, SUITE # 101
MESA, AZ 85201-6764

SHERYL A. SWEENEY, ESQ.
RYLEY, CARLOCK & APPLEWHITE
101 NORTH FIRST AVENUE, SUITE 2600
PHOENIX, AZ 85003-1973

WILLIAM D. BAKER, ESQ.
ELLIS & BAKER
2111 EAST HIGHLAND, SUITE 355
PHOENIX, AZ 85016

JAY I. MOYES, ESQ.
MOYES STOREY
3003 NORTH CENTRAL AVENUE, SUITE 1250
PHOENIX, AZ 85001-2199

CAJUN ELECTRIC POWER COOP.
112 TELLY STREET
NEW ROADS, LA 70760

CALIFORNIA INDEPENDENT SYSTEM
OPERATOR
151 BLUE RAVEEN ROAD
FOLSOM, CA 95630

CENTRAL LOUISIANA ELECTRIC COMPANY
P.O. BOX 5000
PINEVILLE, LA 71361-5000

CINERGY SERVICES, INC.
139 EAST 4 STREET, E.F. 401
CINCINNATI, OH 45201

CITIZENS LEHMAN POWER SALES
160 FEDERAL STREET
BOSTON, MA 02110

CITY OF WICKENBURG
MR. TOM CANDELARIA
155 N. TEGNER STREET
WICKENBURG, AZ 58390-1456

MR. W.A. DUNN, CHAIRMAN
ELECTRICAL DISTRICT NO. 3
ELECTRICAL DISTRICT NO. 1
41630 W. LOUIS JOHNSON DR.
MARICOPA, AZ 85239

ELIZABETH STORY, ADMINISTRATOR
TONOPAH IRRIGATION DISTRICT
P.O. BOX 159
TONOPAH, AZ 85354

HENRY A. BRUBAKER, PRESIDENT
AGUILA IRRIGATION DISTRICT
P.O. BOX 263
AGUILA, AZ 85320

JACKIE A. MECK, MANAGER
BUCKEYE WATER CONSERVATION &
DRAINAGE DISTRICT
P.O. BOX 1726
BUCKEYE, AZ 85326-0160

H.C. DOUGLAS, PRESIDENT
ELECTRICAL DISTRICT NO. 6
P.O. BOX 167
QUEEN CREEK, AZ 85242

R.D. JUSTICE, MANAGER
ELECTRICAL DISTRICT NO. 7
14629 W. PEORIA AVE
WADDELL, AZ 85355

JAMES D. DOWNING, P.E.
ELECTRICAL DISTRICT NO. 8
MCMULLEN VALLEY WATER CONSERVATION
& DRAINAGE DISTRICT
P.O. BOX 99
SALOME, AZ 85348

STEPHEN P. PAVICH, PRESIDENT
HARQUAHALA VALLEY POWER DISTRICT
402 S. HARQUAHALA VALLEY RD
TONOPAH, AZ 85354

JAMES R. SWEENEY, GEN. MGR.
MARICOPA COUNTY MUNICIPAL WATER
CONSERVATION DISTRICT NO. 1
P.O. BOX 900
WADDELL, AZ 85355-0900

STANLEY H. ASHBY, SECRETARY
ROOSEVELT IRRIGATION DISTRICT
103 W. BASELINE ROAD
BUCKEYE, AZ 85326

CITY OF BURBANK
P.O. BOX 631
BURBANK, CA 91503-0631

CITY OF GLENDALE
729 N. AVENUE, 4TH LEVEL
GLENDALE, CA 91206-4496

CITY OF IDAHO FALLS
140 S. CAPITAL AVENUE
IDAHO FALLS, ID 86402

CITY OF NEEDLES
ENOVA ENERGY MANAGEMENT, INC.
12555 HIGH BLUFF DR, SUITE 155
SAN DIEGO, CA 92130

COASTAL ELECTRIC SERVICES COMPANY
COASTAL TOWER
NINE GREENWAY PLAZA
HOUSTON, TX 77046-0995

COLORADO RIVER AGENCY
ROUTE 1, BOX 9-C
PARKER, AZ 85344

COLORADO RIVER COMMISSION OF NEVADA
555 EAST WASHINGTON AVENUE
SUITE 3100
LAS VEGAS, NV 89101

CON AGRA ENERGY SERVICES, INC.
9 CON AGRA DRIVE
OHAMA, NE 68102-5009

COOK INLET ENERGY SUPPLY
10100 SANTA MONICA BLVD, 25TH FLOOR
LOS ANGELES, CA 90024

CORAL POWER, LLC
909 FANNIN, SUITE 700
HOUSTON, TX 77010

US DEPARTMENT OF THE INTERIOR
1849 C Street, N.W.
Washington, D.C. 20240

E PRIME
1331 17TH STREET, SUITE 601
DENVER, CO 80202

EASTERN POWER DISTRIBUITON, INC.
2800 EISENHOWER AVE
ALEXANDRIA, VA 22314

EDISON SOURCE
13191 CROSSROADS PKWY N, SUITE 405
CITY OF INDUSTRY, CA 91746

ELECTRIC CLEARINGHOUSE, INC.
DBA DYNERGY
2999 NORTH 44 ST., SUITE 300
PHOENIX, AZ 85012

ENERGY MASTERS INTERNATIONAL
1385 MENDOTA HEIGHTS ROAD
ST. PAUL, MN 55120-1129

ENGELHARD POWER MARKETING, INC.
101 WOOD AVENUE
ISELIN, NJ 08830-0770

ENTERGY POWER MARKETING CORP.
PARKWOOD TWO BUILDING
10055 GROGAN'S MILL RD, SUITE 500
THE WOODLANDS, TX 77380

FEDERAL ENERGY SALES, INC.
3222 N. RIDGE ROAD
ELYRIA, OH 44035

GULFSTREAM ENERGY, LLC
2930 REVERE ST., STE 202
HOUSTON TX 77098

IDAHO POWER COMPANY
P.O. BOX 70
BOISE, ID 83707

INDUSTRIAL ENERGY APPLICATIONS, INC.
5925 DRY CREEK LANE, NE
CEDAR RAPIDS, IA 52402

INTERCOASTAL ENERGY APPS., INC.
P.O. BOX 657
DES MOINES IA 50303-0657

KOCH ENERGY TRADING, INC.
P.O. BOX 2626
HOUSTON, TX 77252-2626

LA DEPT. OF WATER & POWER
P.O. BOX 111
LOS ANGELES, CA 90012-2694

LG&E ENERGY MARKETING, INC.
220 W. MAIN STREET, 7TH FLOOR
LOUISVILLE, KY 40202

MERCHANT ENERGY GROUP OF THE AMERICAS
151 WEST STREET, SUITE 300
ANNAPOLIS, MD 21401

MORGAN STANLEY CAP. GROUP, INC
1585 BROADWAY
NEW YORK, NY 10036

MONTANA POWER COMPANY
40 E. BROADWAY
BUTTE, ME 59701-9394

NATIONAL GAS & ELECTRIC
3555 TIMMONS, SUITE 1500
HOUSTON, TX 77027

NEVADA POWER COMPANY
P.O. BOX 230
LAS VEGAS, NV 89151-0230

SALT RIVER PROJECT AGRICULTURAL
IMPROVEMENT & POWER DISTRICT
P.O. BOX 52025
PHOENIX, AZ

UTAH MUNICAPAL POWER AGENCY
8722 SOUTH 300 WEST
SANDY, UT 84070

NORTHERN WASCO COUNTY PUD
2345 RIVER ROAD
DALLES, OR 97058

SAN CARLOS IRRIGATION PROJECT
P.O. BOX 250
COOLIDGE, AZ 85228

UTILITY 2000 ENERGY
140 FOURTH AVENUE, S.W.
SUITE 1710
CALGARY, ALBERTA T2P 3N3
CANADA

NP ENERGY INC.
3650 NATIONAL CITY TOWER
LOUISVILLE, KY 40202

SAN DIEGO GAS & ELECTRIC
P.O. BOX 1831
SAN DIEGO, CA 92112-4120

VALLEY ELECTRIC ASSOCIATION
P.O. BOX 237
PAHRUMP, NV 89041

PACIFICORP
825 NE MULTNOMAH
PORTLAND, OR 97232

SNOHOMISH COUNTY PUD #1
P.O. BOX 1107
EVERETT, WA 8206-1107

WASHINGTON WATER POWER
P.O. BOX 3727
SPOKANE, SA 99220-3727

PG&E ENERGY SERVICES
VALERO POWER SERVICES CO.
353 SACRAMENTO STREET, SUITE 1900
SAN FRANCISCO, CA 94111

SONAT POWER MARKETING
1900 FIFTH AVENUE
BIRMINGHAM, AL 35203

WESTERN POWER SERVICES, INC.
12200 NORTH PECOS STREET
DENVER, CO 80234-3439

POWER COMPANY OF AMERICA
2 GREENWICH PLAZA, 2ND FLOOR
GREENWICH, CT 06830

SOUTHERN CALIFORNIA EDISON
2244 WALNUT GROVE AVENUE
ROSEMEAD, CA 91770

WESTERN RESOURCES, INC.
P.O. BOX 889
TOPEKA, KS 66601

POWER EXCHANGE CORP.
450 SANSOME ST., SUITE 1400
SAN FRANCISCO, CA 94111

EL PASO ELECTRIC COMPANY
P.O. BOX 982
EL PASO, TX 79960

WILLIAMS ENERGY SERVICES COMPANY
P.O. BOX 2848
TULSA, OK 74101-9567

PUBLIC SERVICE COMPANY OF NEW MEXICO
ALVARADO SQUARE
ALBUQUERQUE, NM 87158

THE ENERGY AUTHORITY, INC.
76 S. LAURA STREET, STE 1500
JACKSONVILLE, FL 32202

AQUILA ENERGY MARKETING CORP.
P.O. BOX 13207
KANSAS CITY, MO 64199-3207

RAINBOW ENERGY MARKETING CORP.
909 SOUTH 7TH STREET, SUITE 405
BISMARK, SD 58504

TOHONO O'ODHAM UTILITY AUTHORITY
P.O. BOX 816
SELLS, AZ 85635

TRACTABEL ENERGY MARKETING, INC.
1177 WEST LOOP, SUITE 800
HOUSTON, TX 77027

ROCKY MOUNTAIN GENERATION COOP.
5441 BOEING DR., SUITE 200
LOVELAND, CO 80538-8810

NEW MEXICO PUBLIC SERVICE COMMISSION
224 EAST PALACE
SANTA FE, NM 87503

VERIFICATION

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Arizona Public Service Company)	Docket No. EC00-_____-000
Pinnacle West Capital Corporation)	Docket No. ER00-_____-000
Pinnacle West Energy Company)	

VERIFICATION

JACK E. DAVIS

STATE OF ARIZONA)
) ss.
County of Maricopa)

Jack E. Davis, being first duly sworn upon oath, deposes and says:

That he is **Chief Operating Officer and Executive Vice President of Pinnacle West Capital Corporation**, and makes this verification for and on behalf of said corporations, being thereto duly authorized; that he has read the foregoing Application and knows the contents thereof, and that the same is true to the best of his knowledge, information and belief.

Jack Davis

SUBSCRIBED AND SWORN to before me this 27th day of July, 2000.

Joel R. Spitzkoff
Notary Public

My Commission expires:

June 22, 2003

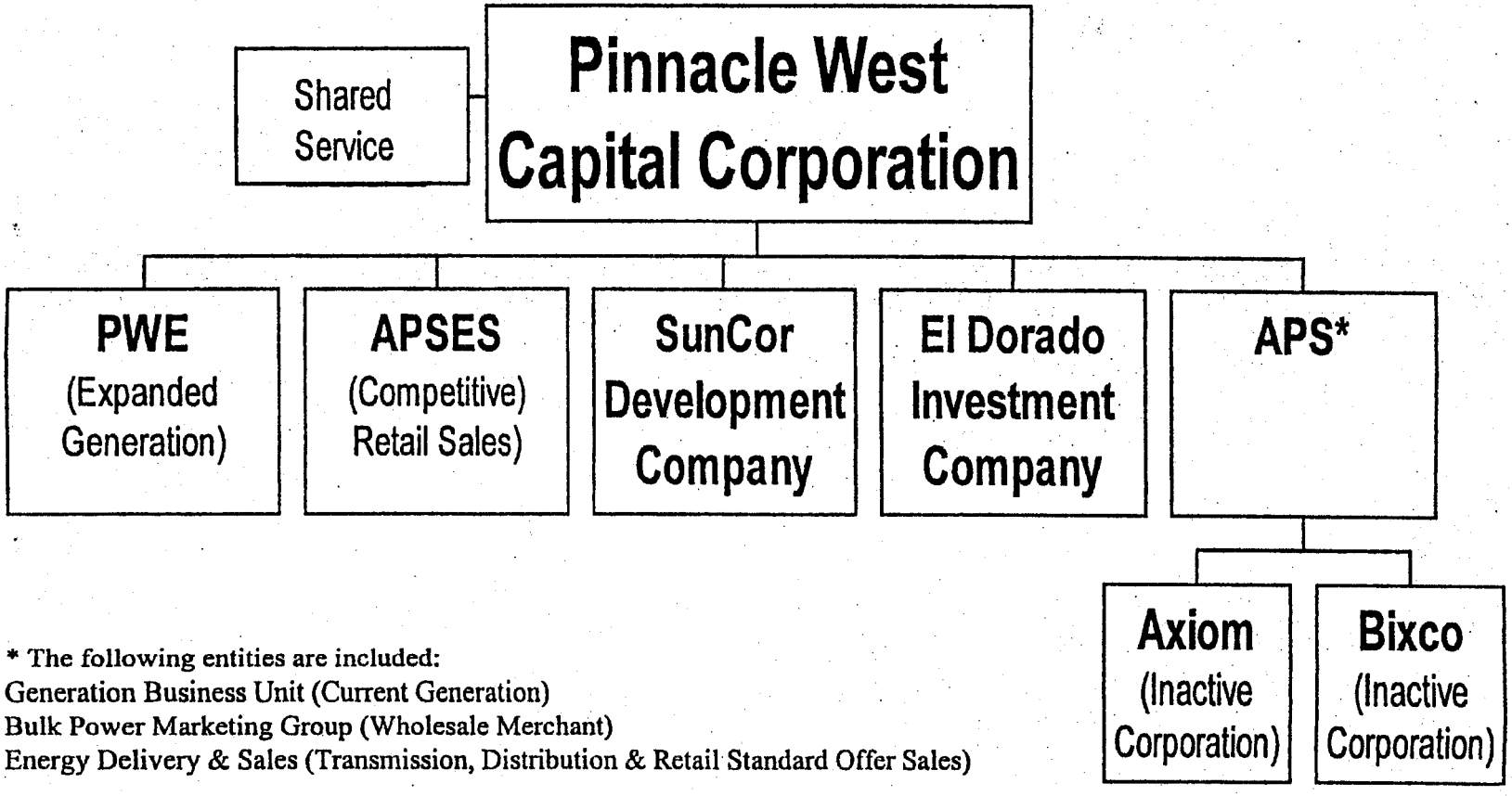
JOEL R. SPITZKOFF
Notary Public - Arizona
MARICOPA COUNTY
My Commission Expires
JUNE 22, 2003

APPENDIX A

Pre - Restructuring

Organizational Chart

APPENDIX A
PNW Corporate Structure
(Prior to Proposed Restructuring)



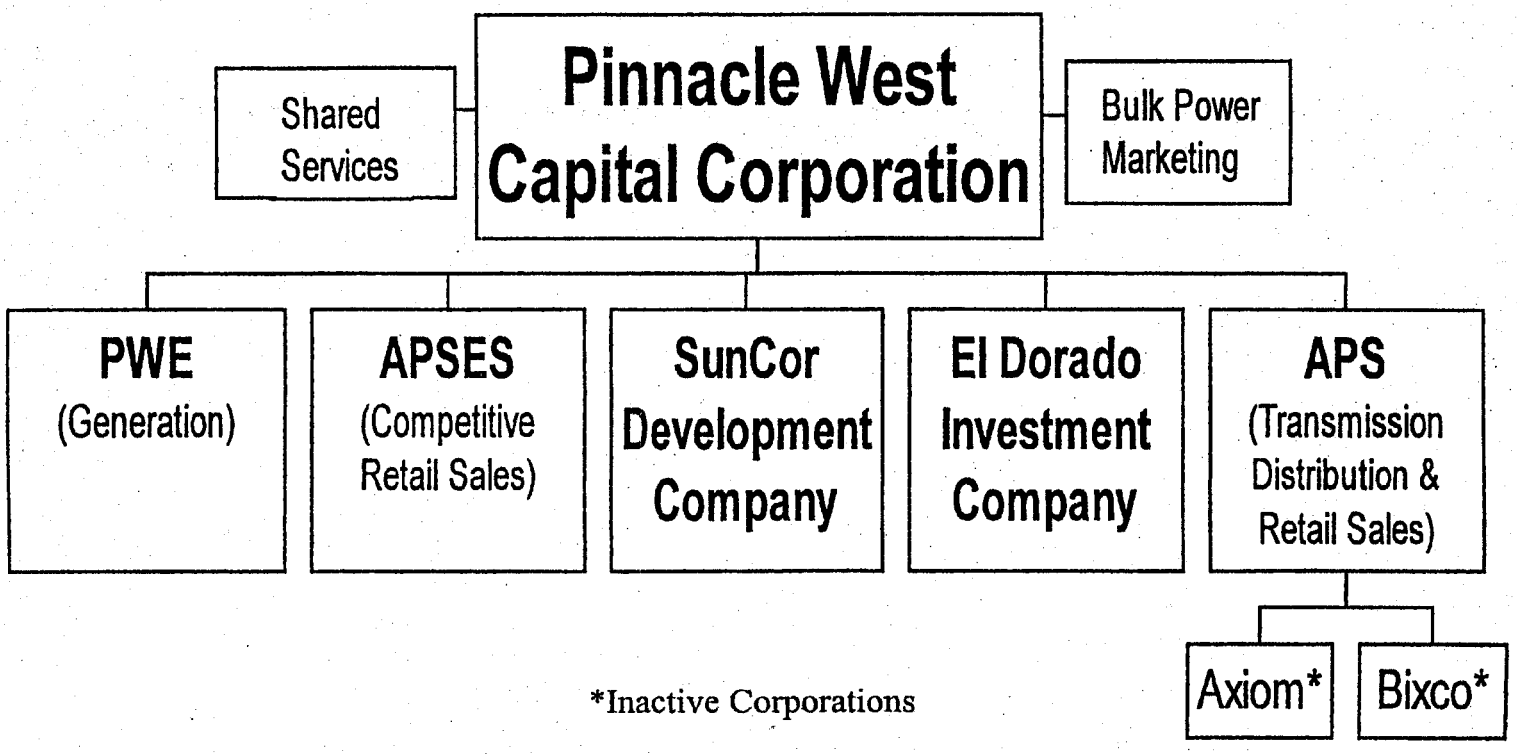
* The following entities are included:
Generation Business Unit (Current Generation)
Bulk Power Marketing Group (Wholesale Merchant)
Energy Delivery & Sales (Transmission, Distribution & Retail Standard Offer Sales)

APPENDIX B

Post - Restructuring

Organizational Chart

Appendix B
PNW Corporate Structure
(Subsequent to Proposed Restructuring)



*Inactive Corporations

ATTACHMENT A

List of the Jurisdictional Transmission Facilities

ATTACHMENT A

LIST OF THE JURISDICTIONAL TRANSMISSION FACILITIES BEING TRANSFERRED FROM APS TO PWE

APS is requesting permission to transfer associated transmission equipment composed of step-up transformers, breakers, disconnect switches, potential and current transformers, metering and tie lines located at the following generating sites that APS is also transferring to its affiliate PWE:

Palo Verde Nuclear Generating Plant
(APS operates the plant and owns 29.1% of all three Units.)

Four Corners Power Plant
(APS operates the plant and owns 100% of Unit 1, 2, and 3. APS owns 15% of Unit 4 and 5.)

Cholla Power Plant
(APS operates the plant but owns only Units 1, 2, and 3. Unit 4 is owned by PacifiCorp.)

West Phoenix Power Plant
(APS operates the plant and owns all units.)

Yucca Power Plant
(APS operates the plant but only owns Units 1, 2, 3, and 4.
Unit 5 is owned by Imperial Irrigation District.)

Ocotillo Power Plant
(APS operates the plant and owns all units.)

Saguaro Power Plant
(APS operates the plant and owns all units.)

Navajo Power Plant
(APS owns 14% of all three units, but does not operate the plant)

Fairview/Douglas
(APS operates the plant and owns the one unit.)

ATTACHMENT B

List of Wholesale Contracts and Service Agreements

Being Transferred From APS to PWCC and PWE

Existing APS Agreements, Tariffs and Service Agreements to be Transferred to Other APS Affiliates

	Rate Schedule Designation	Agreement/Tariff Title	Counter-Party	Assigned to:
1	FPC Rate Schedule No. 5	Axis Station Agreement	Southern California Edison	Pinnacle West Energy
2	FPC Rate Schedule No. 46	United States Department of Interior Kaiparowits Power Coordination Contract	Southern California Edison, San Diego Gas & Electric, United States of America	Pinnacle West Capital Corporation
3	FERC Rate Schedule No.106	Operating Letter for Banking of Arizona Power Authority Energy	Electrical District No. 3	Pinnacle West Capital Corporation
4	FERC Rate Schedule No. 117	Operating Letter for Banking of Arizona Power Authority Energy	Electrical District No. 1	Pinnacle West Capital Corporation
5	FERC Rate Schedule No. 120	Wholesale Power Agreement	Southern California Edison	Pinnacle West Capital Corporation
6	FERC Rate Schedule No. 182	Long Term Power Transaction Agreement	PacifiCorp	Pinnacle West Capital Corporation
7	FERC Rate Schedule No. 211	Four Corners Co-tenancy Agreement and Four Corners Operating Agreement	Southern California Edison, Public Service Company of New Mexico, El Paso Electric, Salt River Project Agricultural Improvement & Power District, Tucson Electric Power Company	Pinnacle West Energy
8	FERC Rate Schedule No. 215	Transmission Service Agreement	Southern California Edison/Colorado River Irrigation Project (Bureau of Indian Affairs)	Pinnacle West Capital Corporation
9	FERC Rate Schedule No. 225	Power Service Agreement	Citizens Utilities Company	Pinnacle West Capital Corporation
10	FERC Rate Schedule No. 229	Navajo Project Co-tenancy Agreement	United States of America, Dept. of Water & Power of Los Angeles, Nevada Power Company, Salt River Project Agricultural Improvement & Power District, Tucson Electric Power Company	Pinnacle West Energy
11	FERC Rate Schedule No. 231	Electric Power Service Agreement	Colorado River Commission of Nevada	Pinnacle West Capital Corporation
12	FERC Rate Schedule No.237	Service Agreement Under FERC Electric Tariff, Original Volume No. 9 of Washington Water Power	Washington Water Power	Pinnacle West Capital Corporation

Existing APS Agreements, Tariffs and Service Agreements
to be Transferred to Other APS Affiliates

	Rate Schedule Designation	Agreement/Tariff Title	Counter-Party	Assigned to:
13	FERC Rate Schedule No. 238	Service Agreement Under FERC Electric Tariff, Original Volume No. 12 of PacifiCorp	PacifiCorp	Pinnacle West Capital Corporation
14	FERC Rate Schedule No. 239	Mutual Netting/Settlement Agreement	PacifiCorp	Pinnacle West Capital Corporation
15	FERC Electric Tariff, Second Revised Volume 3, Service Agreement No. 1	Market Based Rate Tariff Service Agreements	Rainbow Energy Marketing Corp.	Pinnacle West Capital Corporation
16	FERC Electric Tariff, Second Revised Volume 3, Service Agreement No. 2	Market Based Rate Tariff Service Agreements	NP Energy Inc.	Pinnacle West Capital Corporation
17	FERC Electric Tariff, Second Revised Volume 3, Service Agreement No. 3	Market Based Rate Tariff Service Agreements	Valley Electric Association	Pinnacle West Capital Corporation
18	FERC Electric Tariff, Second Revised Volume 3, Service Agreement No. 4	Market Based Rate Tariff Service Agreements	Cinergy Services, Inc.	Pinnacle West Capital Corporation
19	FERC Electric Tariff, Second Revised Volume 3, Service Agreement No. 5	Market Based Rate Tariff Service Agreements	LG&E Energy Marketing Inc.	Pinnacle West Capital Corporation
20	FERC Electric Tariff, Second Revised Volume 3, Service Agreement No. 6	Market Based Rate Tariff Service Agreements	Rocky Mountain Generation Coop.	Pinnacle West Capital Corporation
21	FERC Electric Tariff, Second Revised Volume 3, Service Agreement No. 7	Market Based Rate Tariff Service Agreements	Entergy Power Marketing Corp.	Pinnacle West Capital Corporation
22	FERC Electric Tariff, Second Revised Volume 3, Service Agreement No. 8	Market Based Rate Tariff Service Agreements	E Prime	Pinnacle West Capital Corporation
23	FERC Electric Tariff, Second Revised Volume 3, Service Agreement No. 9	Market Based Rate Tariff Service Agreements	Power Company of America	Pinnacle West Capital Corporation

Existing APS Agreements, Tariffs and Service Agreements to be Transferred to Other APS Affiliates

	Rate Schedule Designation	Agreement/Tariff Title	Counter-Party	Assigned to:
24	FERC Electric Tariff, Second Revised Volume 3, Service Agreement No. 10	Market Based Rate Tariff Service Agreements	Idaho Power Company	Pinnacle West Capital Corporation
25	FERC Electric Tariff, Second Revised Volume 3, Service Agreement No. 11	Market Based Rate Tariff Service Agreements	Sonat Power Marketing	Pinnacle West Capital Corporation
26	FERC Electric Tariff, Second Revised Volume 3, Service Agreement No. 12	Market Based Rate Tariff Service Agreements	American Hunter Energy Inc.	Pinnacle West Capital Corporation
27	FERC Electric Tariff, Second Revised Volume 3, Service Agreement No. 13	Market Based Rate Tariff Service Agreements	Western Power Services, Inc.	Pinnacle West Capital Corporation
28	FERC Electric Tariff, Second Revised Volume 3, Service Agreement No. 14	Market Based Rate Tariff Service Agreements	National Gas & Electric	Pinnacle West Capital Corporation
29	FERC Electric Tariff, Second Revised Volume 3, Service Agreement No. 15	Market Based Rate Tariff Service Agreements	Cajun Electric Power Coop.	Pinnacle West Capital Corporation
30	FERC Electric Tariff, Second Revised Volume 3, Service Agreement No. 17	Market Based Rate Tariff Service Agreements	British Columbia Power Exchange	Pinnacle West Capital Corporation
31	FERC Electric Tariff, Second Revised Volume 3, Service Agreement No. 18	Market Based Rate Tariff Service Agreements	Cook Inlet Energy Supply	Pinnacle West Capital Corporation
32	FERC Electric Tariff, Second Revised Volume 3, Service Agreement No. 19	Market Based Rate Tariff Service Agreements	Snohomish County PUD #1	Pinnacle West Capital Corporation
33	FERC Electric Tariff, Second Revised Volume 3, Service Agreement No. 20	Market Based Rate Tariff Service Agreements	PG&E/ Valero Power Services Inc	Pinnacle West Capital Corporation

Existing APS Agreements, Tariffs and Service Agreements
to be Transferred to Other APS Affiliates

	Rate Schedule Designation	Agreement/Tariff Title	Counter-Party	Assigned to:
34	FERC Electric Tariff, Second Revised Volume 3, Service Agreement No. 21	Market Based Rate Tariff Service Agreements	Western Resources, Inc.	Pinnacle West Capital Corporation
35	FERC Electric Tariff, Second Revised Volume 3, Service Agreement No. 22	Market Based Rate Tariff Service Agreements	MP Energy	Pinnacle West Capital Corporation
36	FERC Electric Tariff, Second Revised Volume 3, Service Agreement No. 23	Market Based Rate Tariff Service Agreements	Tucson Electric Power	Pinnacle West Capital Corporation
37	FERC Electric Tariff, Second Revised Volume 3, Service Agreement No. 24	Market Based Rate Tariff Service Agreements	Coral Power LLC	Pinnacle West Capital Corporation
38	FERC Electric Tariff, Second Revised Volume 3, Service Agreement No. 25	Market Based Rate Tariff Service Agreements	City of Burbank	Pinnacle West Capital Corporation
39	FERC Electric Tariff, Second Revised Volume 3, Service Agreement No. 26	Market Based Rate Tariff Service Agreements	Morgan Stanley Capital Group Inc	Pinnacle West Capital Corporation
40	FERC Electric Tariff, Second Revised Volume 3, Service Agreement No. 27	Market Based Rate Tariff Service Agreements	Tractabel Energy Marketing, Inc.	Pinnacle West Capital Corporation
41	FERC Electric Tariff, Second Revised Volume 3, Service Agreement No. 28	Market Based Rate Tariff Service Agreements	Koch Energy Trading Inc.	Pinnacle West Capital Corporation
42	FERC Electric Tariff, Second Revised Volume 3, Service Agreement No. 29	Market Based Rate Tariff Service Agreements	PG&E Energy Services	Pinnacle West Capital Corporation
43	FERC Electric Tariff, Second Revised Volume 3, Service Agreement No. 30	Market Based Rate Tariff Service Agreements	Williams Energy Services	Pinnacle West Capital Corporation

Existing APS Agreements, Tariffs and Service Agreements
to be Transferred to Other APS Affiliates

	Rate Schedule Designation	Agreement/Tariff Title	Counter-Party	Assigned to:
44	FERC Electric Tariff, Second Revised Volume 3, Service Agreement No. 31	Market Based Rate Tariff Service Agreements	Central Louisiana Electric Company	Pinnacle West Capital Corporation
45	FERC Electric Tariff, Second Revised Volume 3, Service Agreement No. 32	Market Based Rate Tariff Service Agreements	LA Dept of Water & Power	Pinnacle West Capital Corporation
46	FERC Electric Tariff, Second Revised Volume 3, Service Agreement No. 33	Market Based Rate Tariff Service Agreements	Nevada Power Company	Pinnacle West Capital Corporation
47	FERC Electric Tariff, Second Revised Volume 3, Service Agreement No. 34	Market Based Rate Tariff Service Agreements	San Diego Gas & Electric	Pinnacle West Capital Corporation
48	FERC Electric Tariff, Second Revised Volume 3, Service Agreement No. 35	Market Based Rate Tariff Service Agreements	Arizona Electric Power Coop.	Pinnacle West Capital Corporation
49	FERC Electric Tariff, Second Revised Volume 3, Service Agreement No. 36	Market Based Rate Tariff Service Agreements	Salt River Project	Pinnacle West Capital Corporation
50	FERC Electric Tariff, Second Revised Volume 3, Service Agreement No. 37	Market Based Rate Tariff Service Agreements	Southern California Edison	Pinnacle West Capital Corporation
51	FERC Electric Tariff, Second Revised Volume 3, Service Agreement No. 38	Market Based Rate Tariff Service Agreements	Majority Districts (ED6, ED7, ED8, MWD, Harquahala, McMullen, RID, AID, BID & TID)	Pinnacle West Capital Corporation
52	FERC Electric Tariff, Second Revised Volume 3, Service Agreement No. 39	Market Based Rate Tariff Service Agreements	American Electric Power	Pinnacle West Capital Corporation
53	FERC Electric Tariff, Second Revised Volume 3, Service Agreement No. 40	Market Based Rate Tariff Service Agreements	ConAgra Energy Services, Inc.	Pinnacle West Capital Corporation

Existing APS Agreements, Tariffs and Service Agreements
to be Transferred to Other APS Affiliates

	Rate Schedule Designation	Agreement/Tariff Title	Counter-Party	Assigned to:
54	FERC Electric Tariff, Second Revised Volume 3, Service Agreement No. 41	Market Based Rate Tariff Service Agreements	Eastern Power Distribution Inc	Pinnacle West Capital Corporation
55	FERC Electric Tariff, Second Revised Volume 3, Service Agreement No. 42	Market Based Rate Tariff Service Agreements	Morgan Stanley Capital Group Inc	Pinnacle West Capital Corporation
56	FERC Electric Tariff, Second Revised Volume 3, Service Agreement No. 43	Market Based Rate Tariff Service Agreements	Tohono O'Odham Utility Authority	Pinnacle West Capital Corporation
57	FERC Electric Tariff, Second Revised Volume 3, Service Agreement No. 44	Market Based Rate Tariff Service Agreements	Town of Wickenburg	Pinnacle West Capital Corporation
58	FERC Electric Tariff, Second Revised Volume 3, Service Agreement No. 46	Market Based Rate Tariff Service Agreements	California ISO	Pinnacle West Capital Corporation
59	FERC Electric Tariff, Second Revised Volume 3, Service Agreement No. 47	Market Based Rate Tariff Service Agreements	California Power Exchange	Pinnacle West Capital Corporation
60	FERC Electric Tariff, Second Revised Volume 3, Service Agreement No. 48	Market Based Rate Tariff Service Agreements	Electrical District No. 1	Pinnacle West Capital Corporation
61	FERC Electric Tariff, Second Revised Volume 3, Service Agreement No. 49	Market Based Rate Tariff Service Agreements	Electrical District No. 3	Pinnacle West Capital Corporation
62	FERC Electric Tariff, Second Revised Volume 3, Service Agreement No. 50	Market Based Rate Tariff Service Agreements	Public Service Company of New Mexico	Pinnacle West Capital Corporation
63	FERC Electric Tariff, Second Revised Volume 3, Service Agreement No. 51	Market Based Rate Tariff Service Agreements	Merchant Energy Group of the Americas	Pinnacle West Capital Corporation

Existing APS Agreements, Tariffs and Service Agreements
to be Transferred to Other APS Affiliates

	Rate Schedule Designation	Agreement/Tariff Title	Counter-Party	Assigned to:
64	FERC Electric Tariff, Second Revised Volume 3, Service Agreement No. 52	Market Based Rate Tariff Service Agreements	Northern Wasco County PUD	Pinnacle West Capital Corporation
65	FERC Electric Tariff, Second Revised Volume 3, Service Agreement No. 53	Market Based Rate Tariff Service Agreements	San Carlos Irrigation Project	Pinnacle West Capital Corporation
66	FERC Electric Tariff, Second Revised Volume 3, Service Agreement No. 54	Market Based Rate Tariff Service Agreements	City of Idaho Falls	Pinnacle West Capital Corporation
67	FERC Electric Tariff, Second Revised Volume 3, Service Agreement No. 55	Market Based Rate Tariff Service Agreements	San Carlos Irrigation Project	Pinnacle West Capital Corporation
68	FERC Electric Tariff, Second Revised Volume 3, Service Agreement No. 56	Market Based Rate Tariff Service Agreements	Utah Municipal Power Agency	Pinnacle West Capital Corporation
69	FERC Electric Tariff, Second Revised Volume 3, Service Agreement No. 57	Market Based Rate Tariff Service Agreements	The Energy Authority, Inc.	Pinnacle West Capital Corporation
70	FERC Electric Tariff, Volume 1	Electric Coordination Tariff		Pinnacle West Capital Corporation
71	FERC Electric Tariff, Volume 1, Service Agreement No. 1	Electric Coordination Tariff Service Agreement	Snohomish Public Utility District	Pinnacle West Capital Corporation
72	FERC Electric Tariff, Volume 1, Service Agreement No. 2	Electric Coordination Tariff Service Agreement	Electric Clearinghouse Inc.	Pinnacle West Capital Corporation
73	FERC Electric Tariff, Volume 1, Service Agreement No. 3	Electric Coordination Tariff Service Agreement	Gulfstream Energy, LLC	Pinnacle West Capital Corporation
74	FERC Electric Tariff, Volume 1, Service Agreement No. 4	Electric Coordination Tariff Service Agreement	Citizens Utility Company	Pinnacle West Capital Corporation
75	FERC Electric Tariff, Volume 1, Service Agreement No. 5	Electric Coordination Tariff Service Agreement	LG&E Power Marketing, Inc.	Pinnacle West Capital Corporation
76	FERC Electric Tariff, Volume 1, Service Agreement No. 6	Electric Coordination Tariff Service Agreement	Power Exchange Corp.	Pinnacle West Capital Corporation

Existing APS Agreements, Tariffs and Service Agreements
to be Transferred to Other APS Affiliates

	Rate Schedule Designation	Agreement/Tariff Title	Counter-Party	Assigned to:
77	FERC Electric Tariff, Volume 1, Service Agreement No. 8	Electric Coordination Tariff Service Agreement	Intercoastal Power Marketing	Pinnacle West Capital Corporation
78	FERC Electric Tariff, Volume 1, Service Agreement No. 9	Electric Coordination Tariff Service Agreement	Rainbow Energy Marketing Corp.	Pinnacle West Capital Corporation
79	FERC Electric Tariff, Volume 1, Service Agreement No. 10	Electric Coordination Tariff Service Agreement	Town of Wickenburg	Pinnacle West Capital Corporation
80	FERC Electric Tariff, Volume 1, Service Agreement No. 11	Electric Coordination Tariff Service Agreement	Engelhard Power Marketing, Inc.	Pinnacle West Capital Corporation
81	FERC Electric Tariff, Volume 1, Service Agreement No. 13	Electric Coordination Tariff Service Agreement	Coastal Electric Services Company	Pinnacle West Capital Corporation
82	FERC Electric Tariff, Volume 1, Service Agreement No. 14	Electric Coordination Tariff Service Agreement	Utility 2000 Energy	Pinnacle West Capital Corporation
83	FERC Electric Tariff, Volume 1, Service Agreement No. 15	Electric Coordination Tariff Service Agreement	City of Needles	Pinnacle West Capital Corporation
84	FERC Electric Tariff, Volume 1, Service Agreement No. 16	Electric Coordination Tariff Service Agreement	Citizens Lehman Power Sales	Pinnacle West Capital Corporation
85	FERC Electric Tariff, Volume 1, Service Agreement No. 17	Electric Coordination Tariff Service Agreement	Energy Masters International	Pinnacle West Capital Corporation
86	FERC Electric Tariff, Volume 1, Service Agreement No. 18	Electric Coordination Tariff Service Agreement	Aquila Energy Marketing Corp.	Pinnacle West Capital Corporation
87	FERC Electric Tariff, Volume 1, Service Agreement No. 19	Electric Coordination Tariff Service Agreement	Industrial Energy Applications, Inc.	Pinnacle West Capital Corporation
88	FERC Electric Tariff, Volume 1, Service Agreement No. 20	Electric Coordination Tariff Service Agreement	Electrical District No. 3	Pinnacle West Capital Corporation
89	FERC Electric Tariff, Volume 1, Service Agreement No. 21	Electric Coordination Tariff Service Agreement	Western Power Services, Inc.	Pinnacle West Capital Corporation
90	FERC Electric Tariff, Volume 1, Service Agreement No. 22	Electric Coordination Tariff Service Agreement	Federal Energy Sales, Inc.	Pinnacle West Capital Corporation
91	FERC Electric Tariff, Volume 1, Service Agreement No. 23	Electric Coordination Tariff Service Agreement	Cinergy Services, Inc.	Pinnacle West Capital Corporation
92	FERC Electric Tariff, Volume 1, Service Agreement No. 24	Electric Coordination Tariff Service Agreement	Ajo Improvement Company	Pinnacle West Capital Corporation

Existing APS Agreements, Tariffs and Service Agreements to be Transferred to Other APS Affiliates

	Rate Schedule Designation	Agreement/Tariff Title	Counter-Party	Assigned to:
93	FERC Electric Tariff, Volume 1, Service Agreement No. 25	Electric Coordination Tariff Service Agreement	City of Glendale	Pinnacle West Capital Corporation
94	FERC Electric Tariff, Volume 1, Service Agreement No. 26	Electric Coordination Tariff Service Agreement	City of Azusa	Pinnacle West Capital Corporation
95	FERC Electric Tariff, Volume 1, Service Agreement No. 27	Electric Coordination Tariff Service Agreement	Tohono O'Odham Utility Authority	Pinnacle West Capital Corporation
96	FERC Electric Tariff, Volume 1, Service Agreement No. 28	Electric Coordination Tariff Service Agreement	Koch Energy Trading, Inc.	Pinnacle West Capital Corporation
97	FERC Electric Tariff, Volume 1, Service Agreement No. 29	Electric Coordination Tariff Service Agreement	Edison Source	Pinnacle West Capital Corporation
98	FERC Electric Tariff, Volume 1, Service Agreement No. 30	Electric Coordination Tariff Service Agreement	Williams Energy Services Company	Pinnacle West Capital Corporation
99	FERC Electric Tariff, Volume 1, Service Agreement No. 31	Electric Coordination Tariff Service Agreement	Colorado River Agency	Pinnacle West Capital Corporation

ATTACHMENT C

Statement of the Cost of Facilities Involved in

the Transfer of Assets Between APS and PWE

ATTACHMENT C

ARIZONA PUBLIC SERVICE COMPANY
TRANSMISSION EQUIPMENT
BY POWER PLANT AND RELATED SUBSTATION EQUIPMENT
ORIGINAL COSTS AND ACCUMULATED DEPRECIATION
AS OF MAY 31-2000

Power Plants

	Original costs	Accum Depr	Net Book Value
Fairview/Douglas	$186,986	$149,683	$37,303
Ocotillo Power Plant	$2,164,238	$1,405,630	$758,608
Saguaro Power Plant	$1,649,298	$1,397,934	$251,364
Yucca Power Plant	$652,184	$537,451	$114,733
Cholla Steam Plant	$13,197,993	$7,326,215	$5,871,778
Palo Verde Nuclear Plant	$21,126,640	$6,436,097	$14,690,543
Navajo Steam Plant	$2,009,351	$1,203,950	$805,401
West Phoenix Plant	$2,409,236	$1,729,150	$680,086
Four Corners Steam Plant	$3,835,334	$2,530,934	$1,304,400
Total Power Plant Equip in Transmission	$47,231,260	$22,717,044	$24,514,216

ATTACHMENT D

Settlement Agreement Approved by the Arizona Corporation Commission

Authorizing APS to Transfer its Generating Facilities to a Separate Affiliate

BEFORE THE ARIZONA CORPORATION COMMISSION

A.C.C. - DOCKET CONTROL
RECEIVED

MAY 17 1999

DOCUMENTS ARE SUBJECT TO REVIEW BEFORE ACCEPTANCE AS A DOCKETED ITEM.

JIM IRVIN
Commissioner-Chairman
TONY WEST
Commissioner
CARL J. KUNASEK
Commissioner

IN THE MATTER OF THE APPLICATION OF ARIZONA PUBLIC SERVICE COMPANY FOR APPROVAL OF ITS PLAN FOR STRANDED COST RECOVERY	DOCKET NO. E-01345A-98-0473
IN THE MATTER OF THE FILING OF ARIZONA PUBLIC SERVICE COMPANY OF UNBUNDLED TARIFFS PURSUANT TO A.A.C. R14-2-1601 ET SEQ.	DOCKET NO. E-01345A-97-0773
IN THE MATTER OF COMPETITION IN THE PROVISION OF ELECTRIC SERVICES THROUGHOUT THE STATE OF ARIZONA	DOCKET NO. RE-00000C-94-0165

NOTICE OF FILING, APPLICATION FOR APPROVAL OF SETTLEMENT AGREEMENT, AND REQUEST FOR PROCEDURAL ORDER

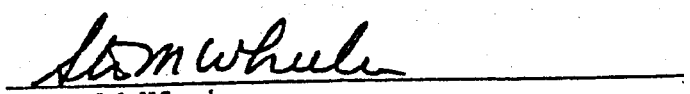
Arizona Public Service Company ("APS") hereby files the attached Settlement Agreement ("Settlement Agreement") dated as of May 17, 1999, between APS and the other signatories to this Agreement (collectively, the "Parties"). The Parties, which includes a broad coalition of large and small consumer interests, entered into the Settlement Agreement for the purpose of agreeing upon terms and conditions for the introduction of competition in generation and other competitive services that they believe to be just, reasonable and in the public interest.

Pursuant to 7.10 of the Settlement Agreement, APS, on behalf of the Parties, respectfully requests that the Commission approve the Settlement Agreement as soon as

practicable in accordance with a procedural schedule that establishes such formal hearings and/or public meetings as are required by applicable legal requirements and that afford interested parties adequate opportunity to comment and be heard on the terms of the Settlement Agreement. APS also requests that the procedural schedule set forth in the April 21, 1999, Procedural Order regarding consideration of APS' stranded costs and unbundled rates (issues which are resolved in the Settlement Agreement) be suspended pending Commission consideration of this Settlement Agreement. Because the Settlement Agreement contemplates Commission approval no later than August 1, 1999, the Parties have attached hereto as Exhibit A a suggested procedural schedule for Commission consideration.

RESPECTFULLY SUBMITTED this 17th day of May, 1999.

SNELL & WILMER L.L.P.



Steven M. Wheeler
Thomas L. Mumaw
Jeffrey B. Guldner

Attorneys for Arizona Public Service Company

661820.01

EXHIBIT A

APS Settlement Procedural Schedule

Filing of Settlement Agreement ..... *May 17*

Procedural Order Issued ..... *May 28*

Filing Date for Testimony from Parties to the Settlement Agreement ..... *June 4*

Filing Date for Testimony from Staff and Intervenors ..... *June 25*

Filing Date for Rebuttal Testimony from Parties to the Settlement Agreement ..... *July 9*

Hearing Begins ..... *July 13*

SETTLEMENT AGREEMENT

May 14, 1999

This settlement agreement ("Agreement") is entered into as of May 14, 1999, by Arizona Public Service Company ("APS" or the "Company") and the various signatories to this Agreement (collectively, the "Parties") for the purpose of establishing terms and conditions for the introduction of competition in generation and other competitive services that are just, reasonable and in the public interest.

INTRODUCTION

In Decision No. 59943, dated December 26, 1996, the Arizona Corporation Commission ("ACC" or the "Commission") established a "framework" for introduction of competitive electric services throughout the territories of public service corporations in Arizona in the rules adopted in A.A.C. R14-2-1601 *et seq.* (collectively, "Electric Competition Rules" as they may be amended from time to time). The Electric Competition Rules established by that order contemplated future changes to such rules and the possibility of waivers or amendments for particular companies under appropriate circumstances. Since their initial issuance, the Electric Competition Rules have been amended several times and are currently stayed pursuant to Decision No. 61311, dated January 5, 1999. During this time, APS, Commission Staff and other interested parties have participated in a number of proceedings, workshops, public comment sessions and individual negotiations in order to further refine and develop a restructured utility industry in Arizona that will provide meaningful customer choice in a manner that is just, reasonable and in the public interest.

This Agreement establishes the agreed upon transition for APS to a restructured entity and will provide customers with competitive choices for generation and certain other retail services. The Parties believe this Agreement will produce benefits for all customers through implementing customer choice and providing rate reductions so that the APS service territory may benefit from economic growth. The Parties also believe this Agreement will fairly treat APS and its shareholders by providing a reasonable opportunity to recover prudently incurred investments and costs, including stranded costs and regulatory assets.

Specifically, the Parties believe the Agreement is in the public interest for the following reasons. First, customers will receive substantial rate reductions. Second, competition will be promoted through the introduction of retail access faster than would have been possible without this Agreement and by the functional separation of APS' power production and delivery functions. Third, economic development and the environment will

benefit through guaranteed rate reductions and the continuation of renewable and energy efficiency programs. Fourth, universal service coverage will be maintained through APS' low income assistance programs and establishment of "provider of last resort" obligations on APS for customers who do not wish to participate in retail access. Fifth, APS will be able to recover its regulatory assets and stranded costs as provided for in this Agreement without the necessity of a general rate proceeding. Sixth, substantial litigation and associated costs will be avoided by amicably resolving a number of important and contentious issues that have already been raised in the courts and before the Commission. Absent approval by the Commission of the settlement reflected by this Agreement, APS would seek full stranded cost recovery and pursue other rate and competitive restructuring provisions different than provided for herein. The other Parties would challenge at least portions of APS' requested relief, including the recovery of all stranded costs. The resulting regulatory hearings and related court appeals would delay the start of competition and drain the resources of all Parties.

NOW, THEREFORE, APS and the Parties agree to the following provisions which they believe to be just, reasonable and in the public interest:

TERMS OF AGREEMENT

ARTICLE I
IMPLEMENTATION OF RETAIL ACCESS

1.1. The APS distribution system shall be open for retail access on July 1, 1999; provided, however, that such retail access to electric generation and other competitive electric services suppliers will be phased in for customers in APS' service territory in accordance with the proposed Electric Competition Rules, as and when such rules become effective, with an additional 140 MW being made available to eligible non-residential customers. The Parties shall urge the Commission to approve Electric Competition Rules, at least on an emergency basis, so that meaningful retail access can begin by July 1, 1999. Unless subject to judicial or regulatory restraint, APS shall open its distribution system to retail access for all customers on January 1, 2001.

1.2. APS will make retail access available to residential customers pursuant to its December 21, 1998, filing with the Commission.

1.3. The Parties acknowledge that APS' ability to offer retail access is contingent upon numerous conditions and circumstances, a number of which are not within the direct control of the Parties. Accordingly, the Parties agree that it may become necessary to modify the terms of retail access to account for such factors, and they further agree to address such matters in good faith and to cooperate in an effort to propose joint resolutions of any such matters.

1.4. APS agrees to the amendment and modification of its Certificate(s) of Convenience and Necessity to permit retail access consistent with the terms of this Agreement. The Commission order adopting this Agreement shall constitute the necessary Commission Order amending and modifying APS' CC&Ns to permit retail access consistent with the terms of this Agreement.

ARTICLE II
RATE MATTERS

2.1. The Company's unbundled rates and charges attached hereto as Exhibit A will be effective as of July 1, 1999. The Company's presently authorized rates and charges shall be deemed its standard offer ("Standard Offer") rates for purposes of this Agreement and the Electric Competition Rules. Bills for Standard Offer service shall indicate individual unbundled service components to the extent required by the Electric Competition Rules.

2.2. Future reductions of standard offer tariff rates of 1.5% for customers having loads of less than 3 MW shall be effective as of July 1, 1999, July 1, 2000, July 1, 2001, July 1, 2002, and July 1, 2003, upon the filing and Commission acceptance of revised tariff sheets reflecting such decreases. For customers having loads greater than 3 MW served on Rate Schedules E-34 and E-35, Standard Offer tariff rates will be reduced: 1.5%, effective July 1, 1999; 1.5% effective July 1, 2000; 1.25% effective July 1, 2001; and .75% effective July 1, 2002. The 1.5% Standard Offer rate reduction to be effective July 1, 1999, includes the rate reduction otherwise required by Decision No. 59601. Such decreases shall become effective by the filing with and acceptance by the Commission of revised tariff sheets reflecting each decrease.

2.3. Customers greater than 3 MW who choose a direct access supplier must give APS one year's advance notice before being eligible to return to Standard Offer service.

2.4. Unbundled rates shall be reduced in the amounts and at the dates set forth in Exhibit A attached hereto upon the filing and Commission acceptance of revised tariff sheets reflecting such decreases.

2.5. This Agreement shall not preclude APS from requesting, or the Commission from approving, changes to specific rate schedules or terms and conditions of service, or the approval of new rates or terms and conditions of service, that do not significantly affect the overall earnings of the Company or materially modify the tariffs or increase the rates approved in this Agreement. Nothing contained in this Agreement shall preclude APS from filing changes to its tariffs or terms and conditions of service which are not inconsistent with its obligations under this Agreement.

2.6. Notwithstanding the rate reduction provisions stated above, the Commission shall, prior to December 31, 2002, approve an adjustment clause or clauses which

will provide full and timely recovery beginning July 1, 2004, of the reasonable and prudent costs of the following:

(1) APS' "provider of last resort" and Standard Offer obligations for service after July 1, 2004, which costs shall be recovered only from Standard Offer and "provider of last resort" customers;

(2) Standard Offer service to customers who have left Standard Offer service or a special contract rate for a competitive generation supplier but who desire to return to Standard Offer service, which costs shall be recovered only from Standard Offer and "provider of last resort" customers;

(3) compliance with the Electric Competition Rules or Commission-ordered programs or directives related to the implementation of the Electric Competition Rules, as they may be amended from time to time, which costs shall be recovered from all customers receiving services from APS; and

(4) Commission-approved system benefit programs or levels not included in Standard Offer rates as of June 30, 1999, which costs shall be recovered from all customers receiving services from APS.

By June 1, 2002, APS shall file an application for an adjustment clause or clauses, together with a proposed plan of administration, and supporting testimony. The Commission shall thereafter issue a procedural order setting such adjustment clause application for hearing and including reasonable provisions for participation by other parties. The Commission order approving the adjustment clauses shall also establish reasonable procedures pursuant to which the Commission, Commission Staff and interested parties may review the costs to be recovered. By June 30, 2003, APS will file its request for the specific adjustment clause factors which shall, after hearing and Commission approval, become effective July 1, 2004. APS shall be allowed to defer costs covered by this Section 2.6 when incurred for later full recovery pursuant to such adjustment clause or clauses, including a reasonable return.

2.7. By June 30, 2003, APS shall file a general rate case with prefiled testimony and supporting schedules and exhibits; provided, however, that any rate changes resulting therefrom shall not become effective prior to July 1, 2004.

2.8. APS shall not be prevented from seeking a change in unbundled or Standard Offer rates prior to July 1, 2004, in the event of (a) conditions or circumstances which constitute an emergency, such as the inability to finance on reasonable terms, or (b) material changes in APS' cost of service for Commission regulated services resulting from federal, tribal,

state or local laws, regulatory requirements, judicial decision, actions or orders. Except for the changes otherwise specifically contemplated by this Agreement, unbundled and Standard Offer rates shall remain unchanged until at least July 1, 2004.

ARTICLE III
REGULATORY ASSETS AND STRANDED COSTS

3.1. APS currently recovers regulatory assets through July 1, 2004, pursuant to Commission Decision No. 59601 in accordance with the provisions of this Agreement.

3.2. APS has demonstrated that its allowable stranded costs after mitigation (which result from the impact of retail access), exclusive of regulatory assets, are at least $533 million net present value.

3.3. The Parties agree that APS should not be allowed to recover $183 million net present value of the amounts included above. APS shall have a reasonable opportunity to recover $350 million net present value through a competitive transition charge ("CTC") set forth in Exhibit A attached hereto. Such CTC shall remain in effect until December 31, 2004, at which time it will terminate. If by that date APS has recovered more or less than $350 million net present value, as calculated in accordance with Exhibit B attached hereto, then the nominal dollars associated with any excess recovery/under recovery shall be credited/debited against the costs subject to recovery under the adjustment clause set forth in Section 2.6(3).

3.4. The regulatory assets to be recovered under this Agreement, after giving effect to the adjustments set forth in Section 3.3, shall be amortized in accordance with Schedule C of Exhibit A attached hereto.

3.5. Neither the Parties nor the Commission shall take any action that would diminish the recovery of APS' stranded costs or regulatory assets provided for herein. The Company's willingness to enter into this Agreement is based upon the Commission's irrevocable promise to permit recovery of the Company's regulatory assets and stranded costs as provided herein. Such promise by the Commission shall survive the expiration of the Agreement and shall be specifically enforceable against this and any future Commission.

ARTICLE IV
CORPORATE STRUCTURE

4.1. The Commission will approve the formation of an affiliate or affiliates of APS to acquire at book value the competitive services assets as currently required by the Electric Competition Rules. In order to facilitate the separation of such assets efficiently and at the lowest possible cost, the Commission shall grant APS a two-year extension of time until

December 31, 2002, to accomplish such separation. A similar two-year extension shall be authorized for compliance with A.A.C. R14-2-1606(B).

4.2. Approval of this Agreement by the Commission shall be deemed to constitute all requisite Commission approvals for (1) the creation by APS or its parent of new corporate affiliates to provide competitive services including, but not limited to, generation sales and power marketing, and the transfer thereto of APS' generation assets and competitive services, and (2) the full and timely recovery through the adjustment clause referred to in Section 2.6 above for all of the reasonable and prudent costs so incurred in separating competitive generation assets and competitive services as required by proposed A.A.C. R14-2-1615, exclusive of the costs of transferring the APS power marketing function to an affiliate. The assets and services to be transferred shall include the items set forth on Exhibit C attached hereto. Such transfers may require various regulatory and third party approvals, consents or waivers from entities not subject to APS' control, including the FERC and the NRC. No Party to this Agreement (including the Commission) will oppose, or support opposition to, APS requests to obtain such approvals, consents or waivers.

4.3. Pursuant to A.R.S. § 40-202(L), the Commission's approval of this Agreement shall exempt any competitive service provided by APS or its affiliates from the application of various provisions of A.R.S. Title 40, including A.R.S. §§ 40-203, 40-204(A), 40-204(B), 40-248, 40-250, 40-251, 40-285, 40-301, 40-302, 40-303, 40-321, 40-322, 40-331, 40-332, 40-334, 40-365, 40-366, 40-367 and 40-401.

4.4. APS' subsidiaries and affiliates (including APS' parent) may take advantage of competitive business opportunities in both energy and non-energy related businesses by establishing such unregulated affiliates as they deem appropriate, which will be free to operate in such places as they may determine. The APS affiliate or affiliates acquiring APS' generating assets may be a participant in the energy supply market within and outside of Arizona. Approval of this Agreement by the Commission shall be deemed to include the following specific determinations required under Sections 32(c) and (k)(2) of the Public Utility Holding Company Act of 1935:

> APS or an affiliate is authorized to establish a subsidiary company, which will seek exempt wholesale generator ("EWG") status from the Federal Energy Regulatory Commission, for the purposes of acquiring and owning Generation Assets.
>
> The Commission has determined that allowing the Generation Assets to become "eligible facilities," within the meaning of Section 32 of the Public Utility Holding Company Act ("PUHCA"), and owned by an APS EWG affiliate (1) will benefit consumers, (2) is in the public interest, and (3) does not violate Arizona law.

The Commission has sufficient regulatory authority, resources and access to the books and records of APS and any relevant associate, affiliate, or subsidiary company to exercise its duties under Section 32(k) of PUHCA.

APS will purchase any electric energy from its EWG affiliate at market based rates. This Commission has determined that (1) the proposed transaction will benefit consumers and does not violate Arizona law; (2) the proposed transaction will not provide APS' EWG affiliate an unfair competitive advantage by virtue of its affiliation with APS; (3) the proposed transaction is in the public interest.

The APS affiliate or affiliates acquiring APS' generating assets will be subject to regulation by the Commission, to the extent otherwise permitted by law, to no greater manner or extent than that manner and extent of Commission regulation imposed upon other owners or operators of generating facilities.

4.5. The Commission's approval of this Agreement will constitute certain waivers to APS and its affiliates (including its parent) of the Commission's existing affiliate interest rules (A.A.C. R14-2-801, *et seq.*), and the rescission of all or portions of certain prior Commission decisions, all as set forth on Exhibit D attached hereto.

4.6. The Parties reserve their rights under Sections 205 and 206 of the Federal Power Act with respect to the rates of any APS affiliate formed under the provisions of this Article IV.

ARTICLE V
WITHDRAWAL OF LITIGATION

5.1. Upon receipt of a final order of the Commission approving this Agreement that is no longer subject to judicial review, APS and the Parties shall withdraw with prejudice all of their various court appeals of the Commission's competition orders.

ARTICLE VI
APPROVAL BY THE COMMISSION

6.1. This Agreement shall not become effective until the issuance of a final Commission order approving this Agreement without modification on or before August 1, 1999. In the event that the Commission fails to approve this Agreement without modification according to its terms on or before August 1, 1999, any Party to this Agreement may withdraw from this Agreement and shall thereafter not be bound by its provisions; provided, however, that if APS withdraws from this Agreement, the Agreement shall be null and void and of no further force and effect. In any event, the rate reduction provisions of this Agreement shall not take effect until this Agreement is approved. Parties so withdrawing shall be free to pursue

their respective positions without prejudice. Approval of this Agreement by the Commission shall make the Commission a Party to this Agreement and fully bound by its provisions.

6.2. The Parties agree that they shall make all reasonable and good faith efforts necessary to (1) obtain final approval of this Agreement by the Commission, and (2) ensure full implementation and enforcement of all the terms and conditions set forth in this Agreement. Neither the Parties nor the Commission shall take or propose any action which would be inconsistent with the provisions of this Agreement. All Parties shall actively defend this Agreement in the event of any challenge to its validity or implementation.

ARTICLE VII
MISCELLANEOUS MATTERS

7.1. To the extent any provision of this Agreement is inconsistent with any existing or future Commission order, rule or regulation or is inconsistent with the Electric Competition Rules as now existing or as may be amended in the future, the provisions of this Agreement shall control and the approval of this Agreement by the Commission shall be deemed to constitute a Commission-approved variation or exemption to any conflicting provision of the Electric Competition Rules.

7.2. The provisions of this Agreement shall be implemented and enforceable notwithstanding the pendency of a legal challenge to the Commission's approval of this Agreement, unless such implementation and enforcement is stayed or enjoined by a court having jurisdiction over the matter. If any portion of the Commission order approving this Agreement or any provision of this Agreement is declared by a court to be invalid or unlawful in any respect, then (1) APS shall have no further obligations or liability under this Agreement, including, but not limited to, any obligation to implement any future rate reductions under Article II not then in effect, and (2) the modifications to APS' certificates of convenience and necessity referred to in Section 1.4 shall be automatically revoked, in which event APS shall use its best efforts to continue to provide noncompetitive services (as defined in the proposed Electric Competition Rules) at then current rates with respect to customer contracts then in effect for competitive generation (for the remainder of their term) to the extent not prohibited by law and subject to applicable regulatory requirements.

7.3. The terms and provisions of this Agreement apply solely to and are binding only in the context of the purposes and results of this Agreement and none of the positions taken herein by any Party may be referred to, cited or relied upon by any other Party in any fashion as precedent or otherwise in any other proceeding before this Commission or any other regulatory agency or before any court of law for any purpose except in furtherance of the purposes and results of this Agreement.

7.4. This Agreement represents an attempt to compromise and settle disputed claims regarding the prospective just and reasonable rate levels, and the terms and conditions

of competitive retail access, for APS in a manner consistent with the public interest and applicable legal requirements. Nothing contained in this Agreement is an admission by APS that its current rate levels or rate design are unjust or unreasonable.

7.5. As part of this Agreement, APS commits that it will continue the APS Community Action Partnership (which includes weatherization, facility repair and replacement, bill assistance, health and safety programs and energy education) in an annual amount of at least $500,000 through July 1, 2004. Additionally, the Company will, subject to Commission approval, continue low income rates E-3 and E-4 under their current terms and conditions.

7.6. APS shall actively support the Arizona Independent Scheduling Administrator ("AISA") and the formation of the Desert Star Independent System Operator. APS agrees to modify its OATT to be consistent with any FERC approved AISA protocols. The Parties reserve their rights with respect to any AISA protocols, including the right to challenge or seek modifications to, or waivers from, such protocols. APS shall file changes to its existing OATT consistent with this section within ten (10) days of Commission approval of this Agreement pursuant to Section 6.1.

7.7. Within thirty (30) days of Commission approval of this Agreement pursuant to Section 6.1, APS shall serve on the Parties an Interim Code of Conduct to address inter-affiliate relationships involving APS as a utility distribution company. APS shall voluntarily comply with this Interim Code of Conduct until the Commission approves a code of conduct for APS in accordance with the Electric Competition Rules that is concurrently effective with codes of conduct for all other Affected Utilities (as defined in the Electric Competition Rules). APS shall meet and confer with the Parties prior to serving its Interim Code of Conduct.

7.8. In the event of any disagreement over the interpretation of this Agreement or the implementation of any of the provisions of this Agreement, the Parties shall promptly convene a conference and in good faith shall attempt to resolve such disagreement.

7.9. The obligations under this Agreement that apply for a specific term set forth herein shall expire automatically in accordance with the term specified and shall require no further action for their expiration.

7.10. The Parties agree and recommend that the Commission schedule public meetings and hearings for consideration of this Agreement. The filing of this Agreement with the Commission shall be deemed to be the filing of a formal request for the expeditious issuance of a procedural schedule that establishes such formal hearings and public meetings as may be necessary for the Commission to approve this Agreement in accordance with

Section 6.1 and that afford interested parties adequate opportunity to comment and be heard on the terms of this Agreement consistent with applicable legal requirements.

DATED at Phoenix, Arizona, as of this 14th day of May, 1999.

RESIDENTIAL UTILITY CONSUMER OFFICE

By Greg Patterson

Title Director

ARIZONA PUBLIC SERVICE COMPANY

By Jack Davis

Title President Delivery & Sales.

ARIZONA COMMUNITY ACTION ASSOCIATION

By Janet R. Regan

Title Executive Director

(Party) _____

By _____

Title _____

ARIZONANS FOR ELECTRIC CHOICE AND COMPETITION, a coalition of companies and associations in support of competition that includes Cable Systems International, BHP Copper, Motorola, Chemical Lime, Intel, [redacted], Honeywell, Allied Signal, Cyprus Climax Metals, Asarco, Phelps Dodge, [redacted], Homebuilders of Central Arizona, Arizona Mining Industry Gets Our Support, Arizona Food Marketing Alliance, Arizona Association of Industries, Arizona Multi-housing Association, Arizona Rock Products Association, Arizona Restaurant Association, [redacted]; and Arizona Retailers Association. **

By Peter A. Woog

Title CHAIRMAN

(Party) _____

By _____

Title _____

Enron is not a signatory to this Agreement

** Also included: Boeing, Az School Board Association, National Federation [illegible] Alliance

Exhibit A
5/10/99
DA-R1

ELECTRIC DELIVERY RATES

ARIZONA PUBLIC SERVICE COMPANY
Phoenix, Arizona
Filed by: Alan Propper
Title: Director, Pricing and Regulation

A.C.C. No. XXXX
Tariff or Schedule No. DA-R1
Original Tariff
Effective: XXX XX, 1999

DIRECT ACCESS
RESIDENTIAL SERVICE

AVAILABILITY

This rate schedule is available in all certificated retail delivery service territory served by Company and where facilities of adequate capacity and the required phase and suitable voltage are adjacent to the premises served.

APPLICATION

This rate schedule is applicable to customers receiving electric energy on a direct access basis from any certificated Electric Service Provider (ESP) as defined in A.A.C. R14-2-1603. This rate schedule is applicable only to electric delivery required for residential purposes in individual private dwellings and in individually metered apartments when such service is supplied at one point of delivery and measured through one meter. For those dwellings and apartments where electric service has historically been measured through two meters, when one of the meters was installed pursuant to a water heating or space heating rate schedule no longer in effect, the electric service measured by such meters shall be combined for billing purposes.

This rate schedule shall become effective as defined in Company's Terms and Conditions for Direct Access (Schedule #10.)

TYPE OF SERVICE

Service shall be single phase, 60 Hertz, at one standard voltage (120/240 or 120/208 as may be selected by customer subject to availability at the customers premise). Three phase service is furnished under the Company's Conditions Governing Extensions of Electric Distribution Lines and Services (Schedule #3). Transformation equipment is included in cost of extension. Three phase service is required for motors of an individual rated capacity of 7-1/2 HP or more.

METERING REQUIREMENTS

All customers shall comply with the terms and conditions for load profiling or hourly metering specified in Schedule #10.

MONTHLY BILL

The monthly bill shall be the greater of the amount computed under A. or B. below, including the applicable Adjustments.

A. RATE

May – October Billing Cycles (Summer):

	Basic Delivery Service	Distribution	System Benefits	Competitive Transition Charge
$/month	$10.00			
All kWh		$0.04158	$0.00115	$0.00930

November – April Billing Cycles (Winter):

	Basic Delivery Service	Distribution	System Benefits	Competitive Transition Charge
$/month	$10.00			
All kWh		$0.03518	$0.00115	$0.00930

B. MINIMUM $ 10.00 per month

(CONTINUED ON REVERSE SIDE)

ADJUSTMENTS

1. When Metering, Meter Reading or Consolidated Billing are provided by the Customer's ESP, the monthly bill will be credited as follows:

Meter	$1.30 per month
Meter Reading	$0.30 per month
Billing	$0.30 per month

2. The monthly bill is also subject to the applicable proportionate part of any taxes, or governmental impositions which are or may in the future be assessed on the basis of gross revenues of the Company and/or the price or revenue from the electric service sold and/or the volume of energy delivered or purchased for sale and/or sold hereunder.

SERVICES ACQUIRED FROM CERTIFICATED ELECTRIC SERVICE PROVIDERS

Customers served under this rate schedule are responsible for acquiring their own generation and any other required competitively supplied services from an ESP. The Company will provide and bill its transmission and ancillary services on rates approved by the Federal Energy Regulatory Commission to the Scheduling Coordinator who provides transmission service to the Customer's ESP. The Customer's ESP must submit a Direct Access Service Request pursuant to the terms and conditions in Schedule #10.

ON-SITE GENERATION TERMS AND CONDITIONS

Customers served under this rate schedule who have on-site generation connected to the Company's electrical delivery grid shall enter into an Agreement for Interconnection with the Company which shall establish all pertinent details related to interconnection and other required service standards. The Customer does not have the option to sell power and energy to the Company under this tariff.

TERMS AND CONDITIONS

This rate schedule is subject to the Company's Terms and Conditions for Standard Offer and Direct Access Services (Schedule #1) and Schedule #10. These schedules have provisions that may affect customer's monthly bill.

Exhibit A
5/10/99
DA-GS1

ELECTRIC DELIVERY RATES

ARIZONA PUBLIC SERVICE COMPANY
Phoenix, Arizona
Filed by: Alan Propper
Title: Director, Pricing and Regulation

A.C.C. No. XXXX
Tariff or Schedule No. DA-GS1
Original Tariff
Effective: XXX XX, 1999

DIRECT ACCESS
GENERAL SERVICE

AVAILABILITY

This rate schedule is available in all certificated retail delivery service territory served by Company at all points where facilities of adequate capacity and the required phase and suitable voltage are adjacent to the premises served.

APPLICATION

This rate schedule is applicable to customers receiving electric energy on a direct access basis from any certificated Electric Service Provider (ESP) as defined in A.A.C. R14-2-1603. This rate schedule is applicable to all electric service required when such service is supplied at one point of delivery and measured through one meter. For those customers whose electricity is delivered through more than one meter, service for each meter shall be computed separately under this rate unless conditions in accordance with the Company's Schedule #4 (Totalized Metering of Multiple Service Entrance Sections At a Single Premise for Standard Offer and Direct Access Service) are met. For those service locations where electric service has historically been measured through two meters, when one of the meters was installed pursuant to a water heating rate schedule no longer in effect, the electric service measured by such meters shall be combined for billing purposes.

This rate schedule shall become effective as defined in Company's Terms and Conditions for Direct Access (Schedule #10).

This rate schedule is not applicable to residential service, resale service or direct access service which qualifies for Rate Schedule DA-GS10.

TYPE OF SERVICE

Service shall be single or three phase, 60 Hertz, at one standard voltage as may be selected by customer subject to availability at the customer's premise. Three phase service is furnished under the Company's Conditions Governing Extensions of Electric Distribution Lines and Services (Schedule #3). Transformation equipment is included in cost of extension. Three phase service is not furnished for motors of an individual rated capacity of less than 7-1/2 HP, except for existing facilities or where total aggregate HP of all connected three phase motors exceed 12 HP. Three phase service is required for motors of an individual rated capacity of more than 7-1/2 HP.

METERING REQUIREMENTS

All customers shall comply with the terms and conditions for load profiling or hourly metering specified in the Company's Schedule #10.

MONTHLY BILL

The monthly bill shall be the greater of the amount computed under A. or B. below, including the applicable Adjustments.

A. RATE

June – October Billing Cycles (Summer):

	Basic Delivery Service	Distribution	System Benefits	Competitive Transition Charge
$ month	$12.50			
Per kW over 5		$0.721		
Per kWh for the first 2,500 kWh		$0.04255		
Per kWh for the next 100 kWh per kW over 5		$0.04255		
Per kWh for the next 42,000 kWh		$0.02901		
Per kWh for all additional kWh		$0.01811		
Per all kWh			$0.00115	
Per all kW				$2.43

(CONTINUED ON REVERSE SIDE)

A. RATE (continued)

November – May Billing Cycles (Winter):

	Basic Delivery Service	Distribution	System Benefits	Competitive Transition Charge
$/month	$12.50			
Per kW over 5		$0.632		
Per kWh for the first 2,500 kWh		$0.03827		
Per kWh for the next 100 kWh per kW over 5		$0.03827		
Per kWh for the next 42,000 kWh		$0.02600		
Per kWh for all additional kWh		$0.01614		
Per all kWh			$0.00115	
Per all kW				$2.43

PRIMARY AND TRANSMISSION LEVEL SERVICE:

1. For customers served at primary voltage (12.5kV to below 69kV), the Distribution charge will be discounted by 11.6%.
2. For customers served at transmission voltage (69kV or higher), the Distribution charge will be discounted 52.6%.
3. Pursuant to A.A.C. R14-2-1612.K.11, the Company shall retain ownership of Current Transformers (CT's) and Potential Transformers (PT's) for those customers taking service at voltage levels of more than 25kV. For customers whose metering services are provided by an ESP, a monthly facilities charge will be billed, in addition to all other applicable charges shown above, as determined in the service contract based upon the Company's cost of CT and PT ownership, maintenance and operation.

DETERMINATION OF KW

The kW used for billing purposes shall be the average kW supplied during the 15-minute period of maximum use during the month, as determined from readings of the delivery meter.

B. MINIMUM

$12.50 plus $1.74 for each kW in excess of five of either the highest kW established during the 12 months ending with the current month or the minimum kW specified in the agreement for service, whichever is the greater.

ADJUSTMENTS

1. When Metering, Meter Reading or Consolidated Billing are provided by the Customer's ESP, the monthly bill will be credited as follows:

Meter	$4.00 per month
Meter Reading	$0.30 per month
Billing	$0.30 per month

2. The monthly bill is also subject to the applicable proportionate part of any taxes, or governmental impositions which are or may in the future be assessed on the basis of gross revenues of the Company and/or the price or revenue from the electric service sold and/or the volume of energy delivered or purchased for sale and/or sold hereunder.

SERVICES ACQUIRED FROM CERTIFICATED ELECTRIC SERVICE PROVIDERS

Customers served under this rate schedule are responsible for acquiring their own generation and any other required competitively supplied services from an ESP or under the Company's Open Access Transmission Tariff. The Company will provide and bill its transmission and ancillary services on rates approved by the Federal Energy Regulatory Commission to the Scheduling Coordinator who provides transmission service to the Customer's ESP. The Customer's ESP must submit a Direct Access Service Request pursuant to the terms and conditions in Schedule #10.

(CONTINUED ON PAGE 3)

ON-SITE GENERATION TERMS AND CONDITIONS

Customers served under this rate schedule who have on-site generation connected to the Company's electrical delivery grid shall enter into an Agreement for Interconnection with the Company which shall establish all pertinent details related to interconnection and other required service standards. The Customer does not have the option to sell power and energy to the Company under this tariff.

CONTRACT PERIOD

0 – 1,999 kW:	As provided in Company's standard agreement for service.
2,000 kW and above:	Three (3) years, or longer, at Company's option for initial period when construction is required. One (1) year, or longer, at Company's option when construction is not required.

TERMS AND CONDITIONS

This rate schedule is subject to Company's Terms and Conditions for Standard Offer and Direct Access Service (Schedule #1) and the Company's Schedule #10. These Schedules have provisions that may affect customer's monthly bill.

Exhibit A
5/10/99
DA-GS10

ELECTRIC DELIVERY RATES

ARIZONA PUBLIC SERVICE COMPANY
Phoenix, Arizona
Filed by: Alan Propper
Title: Director, Pricing and Regulation

A.C.C. No. XXXX
Tariff or Schedule No. DA-GS10
Original Tariff
Effective: XXX XX, 1999

DIRECT ACCESS
EXTRA LARGE GENERAL SERVICE

AVAILABILITY

This rate schedule is available in all certificated retail delivery service territory served by Company at all points where facilities of adequate capacity and the required phase and suitable voltage are adjacent to the premises served.

APPLICATION

This rate schedule is applicable to customers receiving electric energy on a direct access basis from any certificated Electric Service Provider (ESP) as defined in A.A.C. R14-2-1603. This rate schedule is applicable only to customers whose monthly maximum demand is 3,000 kW or more for three (3) consecutive months in any continuous twelve (12) month period ending with the current month. Service must be supplied at one point of delivery and measured through one meter unless otherwise specified by individual customer contract. For those customers whose electricity is delivered through more than one meter, service for each meter shall be computed separately under this rate unless conditions in accordance with the Company's Schedule #4 (Totalized Metering of Multiple Service Entrance Sections At a Single Premise for Standard Offer and Direct Access Service) are met.

This rate schedule is not applicable to resale service.

This rate schedule shall become effective as defined in Company's Terms and Conditions for Direct Access (Schedule #10).

TYPE OF SERVICE

Service shall be three phase, 60 Hertz, at Company's standard voltages that are available within the vicinity of customer's premise.

METERING REQUIREMENTS

All customers shall comply with the terms and conditions for hourly metering specified in Schedule #10.

MONTHLY BILL

The monthly bill shall be the greater of the amount computed under A. or B. below, including the applicable Adjustments.

A. RATE

	Basic Delivery Service	Distribution	System Benefits	Competitive Transition Charge
$/month	$2,430.00			
per kW		$3.53		$2.82
per kWh		$0.00999	$0.00115	

PRIMARY AND TRANSMISSION LEVEL SERVICE:

1. For customers served at primary voltage (12.5kV to below 69kV), the Distribution charge will be discounted by 4.8%.
2. For customers served at transmission voltage (69kV or higher), the Distribution charge will be discounted 36.7%.
3. Pursuant to A.A.C. R14-2-1612.K.11, the Company shall retain ownership of Current Transformers (CT's) and Potential Transformers (PT's) for those customers taking service at voltage levels of more than 25 kV. For customers whose metering services are provided by an ESP, a monthly facilities charge will be billed, in addition to all other applicable charges shown above, as determined in the service contract based upon the Company's cost of CT and PT ownership, maintenance and operation.

DETERMINATION OF KW

The kW used for billing purposes shall be the greater of:

1. The kW used for billing purposes shall be the average kW supplied during the 15-minute period (or other period as specified by individual customer's contract) of maximum use during the month, as determined from readings of the delivery meter.

2. The minimum kW specified in the agreement for service or individual customer contract.

(CONTINUED ON REVERSE SIDE)

B. MINIMUM

$2,430.00 per month plus $1.74 per kW per month.

ADJUSTMENTS

1. When Metering, Meter Reading or Consolidated Billing are provided by the Customer's ESP, the monthly bill will be credited as follows:

Meter	$55.00 per month
Meter Reading	$ 0.30 per month
Billing	$ 0.30 per month

2. The monthly bill is also subject to the applicable proportionate part of any taxes, or governmental impositions which are or may in the future be assessed on the basis of gross revenues of the Company and/or the price or revenue from the electric service sold and/or the volume of energy delivered or purchased for sale and/or sold hereunder.

SERVICES ACQUIRED FROM CERTIFICATED ELECTRIC SERVICE PROVIDERS

Customers served under this rate schedule are responsible for acquiring their own generation and any other required competitively supplied services from an ESP. The Company will provide and bill its transmission and ancillary services on rates approved by the Federal Energy Regulatory Commission to the Scheduling Coordinator who provides transmission service to the Customer's ESP. The Customer's ESP must submit a Direct Access Service Request pursuant to the terms and conditions in Schedule #10.

ON-SITE GENERATION TERMS AND CONDITIONS

Customers served under this rate schedule who have on-site generation connected to the Company's electrical delivery grid shall enter into an Agreement for Interconnection with the Company which shall establish all pertinent details related to interconnection and other required service standards. The Customer does not have the option to sell power and energy to the Company under this tariff.

CONTRACT PERIOD

For service locations in:

a) Isolated Areas: Ten (10) years, or longer, at Company's option, with standard seven (7) year termination period.
b) Other Areas: Three (3) years, or longer, at Company's option.

TERMS AND CONDITIONS

This rate schedule is subject to Company's Terms and Conditions for Standard Offer and Direct Access Service (Schedule #1) and the Company's Schedule #10. These schedules have provisions that may affect customer's monthly bill.

Exhibit A
5/13/99
DA-GS11

ELECTRIC DELIVERY RATES

ARIZONA PUBLIC SERVICE COMPANY
Phoenix, Arizona
Filed by: Alan Propper
Title: Director, Pricing and Regulation

A.C.C. No. XXXX
Tariff or Schedule No. DA-GS11
Original Tariff
Effective: XXXXX, 1999

DIRECT ACCESS
RALSTON PURINA

AVAILABILITY

This rate schedule is available in all certificated retail delivery service territory served by Company at all points where facilities of adequate capacity and the required phase and suitable voltage are adjacent to the premises served.

APPLICATION

This rate schedule is applicable only to Ralston Purina (Site #863970289) when it receives electric energy on a direct access basis from any certificated Electric Service Provider (ESP) as defined in A.A.C. R14-2-1603. Service must be supplied as specified by individual customer contract and the Company's Schedule #4 (Totalized Metering of Multiple Service Entrance Sections At a Single Premise for Standard Offer and Direct Access Service).

This rate schedule is not applicable to resale service.

This rate schedule shall become effective as defined in Company's Terms and Conditions for Direct Access (Schedule #10).

TYPE OF SERVICE

Service shall be three phase, 60 Hertz, at 12.5 kV.

METERING REQUIREMENTS

Customer shall comply with the terms and conditions for hourly metering specified in Schedule #10.

MONTHLY BILL

The monthly bill shall be the greater of the amount computed under A. or B. below, including the applicable Adjustments.

A. RATE

	Basic Delivery Service	Distribution	System Benefits	Competitive Transition Charge
$/month	$2,430.00			
per kW		$2.58		$1.86
per kWh		$0.00732	$0.00115	

DETERMINATION OF KW

The kW used for billing purposes shall be the greater of:

1. The kW used for billing purposes shall be the average kW supplied during the 15-minute period (or other period as specified by individual customer's contract) of maximum use during the month, as determined from readings of the delivery meter.

2. The minimum kW specified in the agreement for service or individual customer contract.

B. MINIMUM

$2,430.00 per month plus $1.74 per kW per month.

ADJUSTMENTS

1. When Metering, Meter Reading or Consolidated Billing are provided by the Customer's ESP, the monthly bill will be credited as follows:

Meter	$55.00 per month
Meter Reading	$ 0.30 per month
Billing	$ 0.30 per month

2. The monthly bill is also subject to the applicable proportionate part of any taxes, or governmental impositions which are or may in the future be assessed on the basis of gross revenues of the Company and/or the price or revenue from the electric service sold and/or the volume of energy delivered or purchased for sale and/or sold hereunder.

(CONTINUED ON REVERSE SIDE)

SERVICES ACQUIRED FROM CERTIFICATED ELECTRIC SERVICE PROVIDERS

Customer is responsible for acquiring its own generation and any other required competitively supplied services from an ESP. The Company will provide and bill its transmission and ancillary services on rates approved by the Federal Energy Regulatory Commission to the Scheduling Coordinator who provides transmission service to the Customer's ESP. The Customer's ESP must submit a Direct Access Service Request pursuant to the terms and conditions in Schedule #10.

ON-SITE GENERATION TERMS AND CONDITIONS

If Customer has on-site generation connected to the Company's electrical delivery grid, it shall enter into an Agreement for Interconnection with the Company which shall establish all pertinent details related to interconnection and other required service standards. The Customer does not have the option to sell power and energy to the Company under this tariff.

TERMS AND CONDITIONS

This rate schedule is subject to Company's Terms and Conditions for Standard Offer and Direct Access Service (Schedule #1) and the Company's Schedule #10. These schedules have provisions that may affect customer's monthly bill.

Exhibit A
5/13/99
DA-GS12

ELECTRIC DELIVERY RATES

ARIZONA PUBLIC SERVICE COMPANY
Phoenix, Arizona
Filed by: Alan Propper
Title: Director, Pricing and Regulation

A.C.C. No. XXXX
Tariff or Schedule No. DA-GS12
Original Tariff
Effective: XXX XX, 1999

DIRECT ACCESS
BHP COPPER

AVAILABILITY

This rate schedule is available in all certificated retail delivery service territory served by Company at all points where facilities of adequate capacity and the required phase and suitable voltage are adjacent to the premises served.

APPLICATION

This rate schedule is applicable only to BHP Copper (Site #774932285) when it receives electric energy on a direct access basis from any certificated Electric Service Provider (ESP) as defined in A.A.C. R14-2-1603. Service must be supplied as specified by individual customer contract and the Company's Schedule #4 (Totalized Metering of Multiple Service Entrance Sections At a Single Premise for Standard Offer and Direct Access Service).

This rate schedule is not applicable to resale service.

This rate schedule shall become effective as defined in Company's Terms and Conditions for Direct Access (Schedule #10).

TYPE OF SERVICE

Service shall be three phase, 60 Hertz, at 12.5 kV or higher.

METERING REQUIREMENTS

Customer shall comply with the terms and conditions for hourly metering specified in Schedule #10.

MONTHLY BILL

The monthly bill shall be the greater of the amount computed under A. or B. below, including the applicable Adjustments.

A. RATE

	Basic Delivery Service	Distribution at Primary Voltage	Distribution at Transmission Voltage	System Benefits	Competitive Transition Charge
$/month	$2,430.00				
per kW		$2.35	$1.22		$1.54
per kWh		$0.00665	$0.00346	$0.00115	

PRIMARY AND TRANSMISSION LEVEL SERVICE:

Pursuant to A.A.C. R14-2-1612.K.11, the Company shall retain ownership of Current Transformers (CT's) and Potential Transformers (PT's) for those customers taking service at voltage levels of more than 25 kV. For customers whose metering services are provided by an ESP, a monthly facilities charge will be billed, in addition to all other applicable charges shown above, as determined in the service contract based upon the Company's cost of CT and PT ownership, maintenance and operation.

DETERMINATION OF KW

The kW used for billing purposes shall be the greater of:

1. The kW used for billing purposes shall be the average kW supplied during the 30-minute period (or other period as specified by individual customer's contract) of maximum use during the month, as determined from readings of the delivery meter.

2. The minimum kW specified in the agreement for service or individual customer contract.

B. MINIMUM

$2,430.00 per month plus $1.74 per kW per month.

(CONTINUED ON REVERSE SIDE)

ADJUSTMENTS

1. When Metering, Meter Reading or Consolidated Billing are provided by the Customer's ESP, the monthly bill will be credited as follows:

Meter	$5.00 per month
Meter Reading	$ 0.30 per month
Billing	$ 0.30 per month

2. The monthly bill is also subject to the applicable proportionate part of any taxes, or governmental impositions which are or may in the future be assessed on the basis of gross revenues of the Company and/or the price or revenue from the electric service sold and/or the volume of energy delivered or purchased for sale and/or sold hereunder.

SERVICES ACQUIRED FROM CERTIFICATED ELECTRIC SERVICE PROVIDERS

Customer is responsible for acquiring its own generation and any other required competitively supplied services from an ESP. The Company will provide and bill its transmission and ancillary services on rates approved by the Federal Energy Regulatory Commission to the Scheduling Coordinator who provides transmission service to the Customer's ESP. The Customer's ESP must submit a Direct Access Service Request pursuant to the terms and conditions in Schedule #10.

ON-SITE GENERATION TERMS AND CONDITIONS

If Customer has on-site generation connected to the Company's electrical delivery grid, it shall enter into an Agreement for Interconnection with the Company which shall establish all pertinent details related to interconnection and other required service standards. The Customer does not have the option to sell power and energy to the Company under this tariff.

TERMS AND CONDITIONS

This rate schedule is subject to Company's Terms and Conditions for Standard Offer and Direct Access Service (Schedule #1) and the Company's Schedule #10. These schedules have provisions that may affect customer's monthly bill.

Exhibit A
5/13/99
DA-GS13

ELECTRIC DELIVERY RATES

ARIZONA PUBLIC SERVICE COMPANY
Phoenix, Arizona
Filed by: Alan Propper
Title: Director, Pricing and Regulation

A.C.C. No. XXXX
Tariff or Schedule No. DA-GS13
Original Tariff
Effective: XXX XX, 1999

DIRECT ACCESS
CYPRUS BAGDAD

AVAILABILITY

This rate schedule is available in all certificated retail delivery service territory served by Company at all points where facilities of adequate capacity and the required phase and suitable voltage are adjacent to the premises served.

APPLICATION

This rate schedule is applicable only to Cyprus Bagdad (Site #1209322284) when it receives electric energy on a direct access basis from any certificated Electric Service Provider (ESP) as defined in A.A.C. R14-2-1603. Service must be supplied as specified by individual customer contract and the Company's Schedule #4 (Totalized Metering of Multiple Service Entrance Sections At a Single Premise for Standard Offer and Direct Access Service).

This rate schedule is not applicable to resale service.

This rate schedule shall become effective as defined in Company's Terms and Conditions for Direct Access (Schedule #10).

TYPE OF SERVICE

Service shall be three phase, 60 Hertz, at 115 kV or higher.

METERING REQUIREMENTS

Customer shall comply with the terms and conditions for hourly metering specified in Schedule #10.

MONTHLY BILL

The monthly bill shall be the greater of the amount computed under A. or B. below, including the applicable Adjustments.

A. RATE

	Basic Delivery Service	Distribution	System Benefits	Competitive Transition Charge
$/month	$2,430.00			
per kW		$1.05		$1.34
per kWh		$0.00298	$0.00115	

PRIMARY AND TRANSMISSION LEVEL SERVICE:

Pursuant to A.A.C. R14-2-1612.K.11, the Company shall retain ownership of Current Transformers (CT's) and Potential Transformers (PT's) for those customers taking service at voltage levels of more than 25 kV. For customers whose metering services are provided by an ESP, a monthly facilities charge will be billed, in addition to all other applicable charges shown above, as determined in the service contract based upon the Company's cost of CT and PT ownership, maintenance and operation.

DETERMINATION OF KW

The kW used for billing purposes shall be the greater of:

1. The kW used for billing purposes shall be the average kW supplied during the 30-minute period (or other period as specified by individual customer's contract) of maximum use during the month, as determined from readings of the delivery meter.

2. The minimum kW specified in the agreement for service or individual customer contract.

B. MINIMUM

$2,430.00 per month plus $1.74 per kW per month, until June 30, 2004 when this minimum will no longer be applicable.

(CONTINUED ON REVERSE SIDE)

ADJUSTMENTS

1. When Metering, Meter Reading or Consolidated Billing are provided by the Customer's ESP, the monthly bill will be credited as follows:

Meter	$55.00 per month
Meter Reading	$ 0.30 per month
Billing	$ 0.30 per month

2. The monthly bill is also subject to the applicable proportionate part of any taxes, or governmental impositions which are or may in the future be assessed on the basis of gross revenues of the Company and/or the price or revenue from the electric service sold and/or the volume of energy delivered or purchased for sale and/or sold hereunder.

SERVICES ACQUIRED FROM CERTIFICATED ELECTRIC SERVICE PROVIDERS

Customer is responsible for acquiring its own generation and any other required competitively supplied services from an ESP. The Company will provide and bill its transmission and ancillary services on rates approved by the Federal Energy Regulatory Commission to the Scheduling Coordinator who provides transmission service to the Customer's ESP. The Customer's ESP must submit a Direct Access Service Request pursuant to the terms and conditions in Schedule #10.

ON-SITE GENERATION TERMS AND CONDITIONS

If Customer has on-site generation connected to the Company's electrical delivery grid, it shall enter into an Agreement for Interconnection with the Company which shall establish all pertinent details related to interconnection and other required service standards. The Customer does not have the option to sell power and energy to the Company under this tariff.

TERMS AND CONDITIONS

This rate schedule is subject to Company's Terms and Conditions for Standard Offer and Direct Access Service (Schedule #1) and the Company's Schedule #10. These schedules have provisions that may affect customer's monthly bill.

ARIZONA PUBLIC SERVICE COMPANY

Exhibit A
3/10/99
Schedule A

Competitive Transition Charges
By Direct Access Rate Classes

Line #	Direct Access Rate Class	Competition Transition Charges Effective January 1 of					
		1999	2000	2001	2002	2003	2004
1	Residential, DA-R1 (per kWh)	$ 0.0093	$ 0.0084	$ 0.0063	$ 0.0056	$ 0.0050	$ 0.0036
2	Under 3 mW, DA-GS1, (per kW/mo.)	$ 2.43	$ 2.20	$ 1.66	$ 1.46	$ 1.30	$ 0.94
3	3 mW and Above, DA-GS10 (per kW/mo.)	$ 2.82	$ 2.55	$ 1.89	$ 1.72	$ 1.51	$ 1.09
4	BHP Copper (per kW/mo.)	$ 1.54	$ 1.53	$ 1.06	$ 0.95	$ 0.83	$ 0.61
5	Cyprus Copper (per kW/mo.)	$ 1.34	$ 1.46	$ 1.05	$ 0.94	$ 0.82	$ 0.61
6	Ralston Purina (per kW/mo.)	$ 1.86	$ 1.98	$ 1.50	$ 1.34	$ 1.18	$ 0.87
7	Average Retail (per kWh)	$ 0.0067	$ 0.0061	$ 0.0054	$ 0.0048	$ 0.0043	$ 0.0031

Charges are based upon recovery of $350 million NPV derived from APS' Compliance Filing of 8/21/98 as adjusted to synchronize Direct Access and Standard Offer revenue decreases.

ARIZONA PUBLIC S[illegible]CE COMPANY

Exhibit A
5/13/99
Schedule B

Distribution Charges
By Direct Access Rate Classes

Line #	Direct Access Rate Class	Distribution Charges Effective January 1 of 1999	2000	2001	2002	2003	2004[1]
	Residential, DA-R1						
1	Summer per kWh	$ 0.04158	$ 0.04041	$ 0.03934	$ 0.03837	$ 0.03748	$ 0.03689
2	Winter per kWh	$ 0.03518	$ 0.03419	$ 0.03329	$ 0.03247	$ 0.03172	$ 0.03122
	DA-GS1 (Under 3 mW)						
	Summer Rates						
3	per kW for all kW over 5	$ 0.721	$ 0.691	$ 0.663	$ 0.638	$ 0.615	$ 0.600
4	per kWh for the first 2,500 kWh	$ 0.04255	$ 0.04075	$ 0.03912	$ 0.03763	$ 0.03627	$ 0.03537
5	per kWh for the next 100 kWh per kW over 5	$ 0.04255	$ 0.04075	$ 0.03912	$ 0.03763	$ 0.03627	$ 0.03537
6	per kWh for the next 42,000 kWh	$ 0.02901	$ 0.02779	$ 0.02667	$ 0.02565	$ 0.02473	$ 0.02411
7	per kWh for all additional kWh	$ 0.01811	$ 0.01735	$ 0.01665	$ 0.01602	$ 0.01544	$ 0.01506
	Winter Rates						
8	per kW for all kW over 5	$ 0.652	$ 0.624	$ 0.599	$ 0.576	$ 0.555	$ 0.541
9	per kWh for the first 2,500 kWh	$ 0.03827	$ 0.03666	$ 0.03519	$ 0.03385	$ 0.03263	$ 0.03182
10	per kWh for the next 100 kWh per kW over 5	$ 0.03827	$ 0.03666	$ 0.03519	$ 0.03385	$ 0.03263	$ 0.03182
11	per kWh for the next 42,000 kWh	$ 0.02600	$ 0.02490	$ 0.02390	$ 0.02299	$ 0.02216	$ 0.02161
12	per kWh for all additional kWh	$ 0.01614	$ 0.01546	$ 0.01484	$ 0.01427	$ 0.01376	$ 0.01342
	Voltage Discounts						
13	Primary Voltage	11.6%	12.1%	12.6%	13.1%	13.6%	13.9%
14	Transmission Voltage	52.6%	54.9%	57.2%	59.5%	61.7%	63.3%
	DA-GS10 (3 mW and Above)						
15	per kW	$ 3.53	$ 3.33	$ 3.15	$ 2.98	$ 2.83	$ 2.73
16	per kWh	$ 0.00999	$ 0.00943	$ 0.00892	$ 0.00845	$ 0.00802	$ 0.00774
	Voltage Discounts						
17	Primary Voltage Discount	4.8%	5.1%	5.3%	5.6%	5.9%	6.2%
18	Transmission Voltage Discount	36.7%	38.9%	41.1%	43.4%	45.8%	47.4%
	DA-GS11 (Ralston Purina)						
19	per kW	$ 2.58	$ 2.71	$ 2.57	$ 2.44	$ 2.32	$ 2.25
20	per kWh	$ 0.00732	$ 0.00767	$ 0.00727	$ 0.00691	$ 0.00657	$ 0.00635
	DA-GS12 (BHP Copper)						
21	Primary Voltage Delivery - per kW	$ 2.35	$ 2.30	$ 2.16	$ 2.07	$ 1.99	$ 1.93
22	per kWh	$ 0.00665	$ 0.00651	$ 0.00611	$ 0.00585	$ 0.00561	$ 0.00546
23	Transmission Voltage Delivery - per kW	$ 1.22	$ 1.17	$ 1.03	$ 0.94	$ 0.85	$ 0.80
24	per kWh	$ 0.00346	$ 0.00332	$ 0.00292	$ 0.00266	$ 0.00242	$ 0.00227
	DA-GS13 (Cyprus Bagdad)						
25	per kW	$ 1.05	$ 1.21	$ 1.03	$ 0.94	$ 0.85	$ 0.80
26	per kWh	$ 0.00297	$ 0.00343	$ 0.00292	$ 0.00266	$ 0.00242	$ 0.00227

[1] Transmission voltage customers will not pay Distribution Charges after June 30, 2004

Exhibit A
5/14/99
Schedule C

ARIZONA PUBLIC SERVICE COMPANY

Regulatory Asset Amortization Schedule
(Millions of Dollars)

1999	2000	2001	2002	2003	1/1 - 6/30 2004 [1]	Total [2]
164	158	145	115	86	18	686

[1] Amortization ends 6/30/2004

[2] Includes the disallowance from Section 3.3

5/10/99

Exhibit B

		Annual ACC Jurisdictional Sales of Delivered kWh or kW[1]	x % then Eligible for Access	x Applicable CTC (¢/kWh or $/kW[2])	= Annual Recovery[3]
1999	Residential		20	.93	
	General Service less than 3MW		20	2.43	
	General Service greater than 3MW		20	2.82	
	BHP Copper		20	1.54	
	Cyprus Copper		20	1.34	
	Ralston Purina		20	1.86	
2000	Residential		20	.84	
	General Service less than 3MW		20	2.20	
	General Service greater than 3MW		20	2.55	
	BHP Copper		20	1.53	
	Cyprus Copper		20	1.46	
	Ralston Purina		20	1.98	
2001	Residential		100	.63	
	General Service less than 3MW		100	1.66	
	General Service greater than 3MW		100	1.89	
	BHP Copper		100	1.06	
	Cyprus Copper		100	1.05	
	Ralston Purina		100	1.50	
2002	Residential		100	.56	
	General Service less than 3MW		100	1.46	
	General Service greater than 3MW		100	1.72	
	BHP Copper		100	.95	
	Cyprus Copper		100	.94	
	Ralston Purina		100	1.34	
2003	Residential		100	.50	
	General Service less than 3MW		100	1.30	
	General Service greater than 3MW		100	1.51	
	BHP Copper		100	.83	
	Cyprus Copper		100	.82	
	Ralston Purina		100	1.18	
2004	Residential		100	.36	
	General Service less than 3MW		100	.94	
	General Service greater than 3MW		100	1.09	
	BHP Copper		100	.61	
	Cyprus Copper		100	.61	
	Ralston Purina		100	.87	

[1] This formula assumes no change in APS' distribution service territory. In the event of any material change (e.g. by purchase, sale, expansion, condemnation, etc.) the formula will be adjusted such that APS receives the same opportunity to recover the agreed upon level of costs.

[2] General Service unmetered loads will have a demand calculated for CTC purposes based on contract energy.

[3] At the end of 2004 the net present value will be calculated to compare to the $350 million.

EXHIBIT C

Generation assets include, but are not limited to, APS' interest in the following generating stations:

Palo Verde
Four Corners
Navajo
Cholla
Saguaro
Ocotillo
West Phoenix
Yucca
Douglas
Childs
Irving

including allocated common and general plant, support assets, associated land, fuel supplies and contracts, etc. Generation assets will not include facilities included in APS' FERC transmission rates.

EXHIBIT D

Affiliate Rules Waivers

R14-2-801(5) and R14-2-803, such that the term "reorganization" does not include, and no Commission approval is required for, corporate restructuring that does not directly involve the utility distribution company ("UDC") in the holding company. For example, the holding company may reorganize, form, buy or sell non-UDC affiliates, acquire or divest interests in non-UDC affiliates, etc., without Commission approval.

R14-2-804(A)

R14-2-805(A) shall apply only to the UDC

R14-2-805(A)(2)

R14-2-805(A)(6)

R14-2-805(A)(9), (10), and (11)

Recision of Prior Commission Orders

Section X.C of the "Cogeneration and Small Power Production Policy" attached to Decision No. 52345 (July 27, 1981) regarding reporting requirements for cogeneration information.

Decision No. 55118 (July 24, 1986) - Page 15, Lines 5-1/2 through 13-1/2; Finding of Fact No. 24 relating to reporting requirements under the abolished PPFAC.

Decision No. 55818 (December 14, 1987) in its entirety. This decision related to APS Schedule 9 (Industrial Development Rate) which was terminated by the Commission in Decision No. 59329 (October 11, 1995).

9th and 10th Ordering Paragraphs of Decision No. 56450 (April 13, 1989) regarding reporting requirements under the abolished PPFAC.

Jana Van Ness
Manager
Regulatory Affairs

Tel 602/250-2310
Fax 602/250-3399
e-mail:jvanness@apsc.com
http://www.apsc.com

Mail Station 9909
P.O. Box 53999
Phoenix, AZ 85072-3999

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1999 DEC -1 P 3:48
AZ CORP COMMISSION
DOCUMENT CONTROL

December 1, 1999

Docket Control
Arizona Corporation Commission
1200 West Washington
Phoenix, Arizona 85007

RE: APS Settlement Proceeding
ACC Docket Nos. E-01345A-98-0473, E-01345A-97-0773, RE-00000C-94-0165

Dear Sir or Madam:

Pursuant to the Opinion and Order, Decision No. 61973 in the above referenced Dockets, Arizona Public Service is filing an Addendum to the Settlement Agreement incorporating the modifications required by that Decision. This Addendum has been reviewed and executed by all signatories to the original APS Settlement Agreement.

If you have any questions regarding this filing, please contact me at (602)250-2310.

Sincerely,

Jana Van Ness
Manager
State Regulations

Attachment

Cc: Docket Control (18 copies plus original)
Parties of Record

Addendum to Settlement Agreement

This Addendum is to the Settlement Agreement dated May 14, 1999 (hereafter "Agreement") between Arizona Public Service Company ("APS" or "Company") and the various signatories to the Agreement (collectively with APS, the "Parties"). By signing this Addendum to Settlement Agreement ("Addendum"), the Parties intend to revise certain provisions of the Agreement as directed by the Arizona Corporation Commission ("Commission") in Decision No. 61973 (October 6, 1999) ("Decision"). The Decision adopted and approved the Agreement subject to certain modifications.

I.
Introduction and Recitals

1. On May 14, 1999, the Parties entered into the Agreement;

2. On May 17, 1999, APS filed with the Commission a Notice of Filing Application for Approval of Settlement Agreement and Request for Procedural Order.

3. Commencing on July 14, 1999, and pursuant to a Procedural Order issued by the Hearing Division of the Commission, a full public evidentiary hearing on the Agreement was conducted.

4. On October 6, 1999, the Commission issued its Decision No. 61973 adopting and approving the Agreement as modified in the Decision.

5. The Parties now wish to enter into this Addendum to revise the Agreement as directed in the Decision.

II.
Addendum Agreement

1. Metering, Meter Reading, and Billing Credits

A. The Company's revised unbundled rates and charges reflecting the metering, meter reading, and billing credits required by the Decision are attached hereto as Revised Exhibit A.

B. The revised unbundled rates and charges in Revised Exhibit A to this Addendum are substituted for the corresponding tariffs in Exhibit A to the Agreement.

C. Schedules A through C of Exhibit A to the Agreement are not affected by this Addendum and were adopted and approved by the Commission in the Decision as originally proposed in the Agreement.

2. Advanced Notice for Large Customers. Section 2.3 of the Agreement is replaced with and superceded by the following provision:

> 2.3. Customers greater than 3 MW who choose a direct access supplier must either (a) give APS one year's advance notice before being eligible to return to Standard Offer service, or (b) pay APS for all additional costs incurred as a result of the customer returning to Standard Offer service without providing APS at least one year's advance notice.

3. Deferral of Transfer Costs. Section 2.6(3) of the Agreement is replaced with and superceded by the following provision:

> (3) compliance with the Electric Competition Rules or Commission-ordered programs or directives related to the implementation of the Electric Competition Rules, as they may be amended from time to time, which costs shall be recovered from all customers receiving services from APS, provided however, that no more than sixty-seven percent (67%) of the costs to transfer generation assets to an affiliate or affiliates shall be allowed to be deferred for future collection under this provision; and

4. Rate Matters. Section 2.8 of the Agreement is replaced with and superceded by the following provision:

> 2.8. Neither the Commission nor APS shall be prevented from seeking or authorizing a change in unbundled or Standard Offer rates prior to July 1, 2004, in the event of (a) conditions or circumstances which constitute an emergency, such as an inability to finance on reasonable terms, or (b) material changes in APS' cost of service for Commission-regulated services resulting from federal, tribal, state or local laws, regulatory requirements, judicial decisions, actions or orders. Except for the changes otherwise specifically contemplated by this Agreement, unbundled and Standard Offer rates shall remain unchanged until at least July 1, 2004.

5. Generation Affiliate. Section 4.1 of the Agreement is replaced with and superceded by the following provisions:

4.1. Affiliates.

(1) The Commission will approve the formation of an affiliate or affiliates of APS to acquire at book value the competitive services and assets as currently required by the Electric Competition Rules. In order to facilitate the separation of such assets efficiently and at the lowest possible cost, the Commission shall grant APS a two-year extension of time until December 31, 2002, to accomplish such separation. A similar two-year extension shall be authorized for compliance with A.A.C. R14-2-1606(B).

(2) The affiliate or affiliates formed under this Section 4.1 shall be direct subsidiaries of Pinnacle West Capital Corporation, and not APS.

(3) After the extensions granted in this Section 4.1 have expired, APS shall procure generation for Standard Offer customers from the competitive market as provided for in the Electric Competition Rules. An affiliated generation company formed pursuant to this Section 4.1 may competitively bid for APS' Standard Offer load, but enjoys no automatic privilege outside of the market bid on account of its affiliation with APS.

6. Statutory Waivers. Section 4.3 of the Agreement is deleted in its entirety.

7. Waivers of Affiliate Interest Rules. The Revised Exhibit D to this Addendum setting forth the Affiliate Rules Waivers is substituted for the corresponding Exhibit D to the Agreement so that the proposed waiver of R14-2-804(A) in the Agreement is deleted.

8. Conflicts with Electric Competition Rules. In reliance upon the Commission's directive in Decision No. 61973 (page 9) that "We want to make it clear that the Commission does not intend to revisit the stranded cost portion of the Agreement. It is also not the Commission's intent to undermine the benefits that parties have bargained for," Section 7.1 is replaced with and superseded by the following provision:

> 7.1. Approval of this Agreement by the Commission shall constitute a waiver of any existing Commission order, rule or regulation to the extent necessary to permit performance of the Agreement, as approved by the Commission. Any future Commission order, rule or regulation shall be construed and administered, insofar as possible, in a manner so as not to conflict with the specific provisions of this Agreement, as approved by the Commission. In the event any of the Parties deems a future Commission order, rule or regulation to be inconsistent with the specific provisions of this Agreement, a waiver of the new Commission order, rule or regulation shall be sought.
>
> Nothing in this Agreement is intended to otherwise interfere with the Commission's ability to exercise its regulatory authority by the issuance of orders, rules or regulations. The requirements of this Agreement shall be performed in accordance with the Commission's Electric Competition Rules including any specific waivers granted by the Commission's order approving this Agreement, except where a specific provision of this Agreement would excuse compliance.

9. Interim Code of Conduct. Section 7.7 of the Agreement is replaced with and superceded by the following provision:

> 7.7. Within thirty (30) days of the date of the Commission decision approving this Agreement pursuant to Section 6.1, APS shall file an initial proposed Code of Conduct to address inter-affiliate relationships involving APS as a utility distribution company as required by the Electric Competition Rules and which includes provisions to govern the supply of generation during the two-year extension provided for by Section 4.1 of this Agreement. Interested parties may provide APS with comments on the initial proposed Code of Conduct within sixty (60) days of the date of the Commission decision approving this Agreement. APS will file a final proposed Code of Conduct for Commission approval within ninety (90) days of the date of the Commission decision approving this Agreement. Until the Commission approves a Code of Conduct for APS, APS will voluntarily comply with the initial proposed Code of Conduct or, once filed, the final proposed Code of Conduct.

10. Effect of Addendum. Other than as specifically modified by this Addendum, all provisions of the Agreement remain in full force and effect.

AGREED TO AS OF December 21, **1999:**

RESIDENTIAL UTILITY CONSUMER OFFICE

By Barbara Wytaske

Title Acting Director

ARIZONA PUBLIC SERVICE COMPANY

By Jack Davis

Title President Director Sales

ARIZONA COMMUNITY ACTION ASSOCIATION

By Betty C Pruitt

Title Acting Executive Director

(Party)

By _____

Title _____

ARIZONANS FOR ELECTRIC CHOICE AND COMPETITION, a coalition of companies and associations in support of competition that includes Cable Systems International, BHP Copper, Motorola, Chemical Lime, Intel, Hughes, Honeywell, Allied Signal, Cyprus Climax Metals, Asarco, Phelps Dodge, Homebuilders of Central Arizona, Arizona Mining Industry Gets Our Support, Arizona Food Marketing Alliance, Arizona Association of Industries, Arizona Multi-housing Association, Arizona Rock Products Association, Arizona Restaurant Association, Arizona Retailers Association, Boeing, Arizona School Board Association, National Federation of Independent Business, Arizona Hospital Association, Lockheed Martin, Abbot Labs and Raytheon.

By _____

Title President

(Party)

By _____

Title _____

(Party)

By _____

Title _____

Revised
EXHIBIT D
Affiliate Rules Waivers

R14-2-801(5) and R14-2-803, such that the term "reorganization" does not include, and no Commission approval is required for, corporate restructuring that does not directly involve the utility distribution company ("UDC") in the holding company. For example, the holding company may reorganize, form, buy or sell non-UDC affiliates, acquire or divest interests in non-UDC affiliates, etc., without Commission approval.

R14-2-805(A) shall apply only to the UDC

R14-2-805(A)(2)

R14-2-805(A)(6)

R14-2-805(A)(9), (10), and (11)

Recision of Prior Commission Orders

Section X.C of the "Cogeneration and Small Power Production Policy" attached to Decision No. 52345 (July 27, 1981) regarding reporting requirements for cogeneration information.

Decision No. 55118 (July 24, 1986) - Page 15, Lines 5-1/2 through 13-1/2; Finding of Fact No. 24 relating to reporting requirements under the abolished PPFAC.

Decision No. 55818 (December 14, 1987) in its entirety. This decision related to APS Schedule 9 (Industrial Development Rate) which was terminated by the Commission in Decision No. 59329 (October 11, 1995).

9th and 10th Ordering Paragraphs of Decision No. 56450 (April 13, 1989) regarding reporting requirements under the abolished PPFAC.

659323.02

ELECTRIC DELIVERY RATES

ARIZONA PUBLIC SERVICE COMPANY
Phoenix, Arizona
Filed by: Alan Propper
Title: Director, Pricing and Regulation

ORIGINAL

A.C.C. No. 5351
Tariff or Schedule No. DA-GS1
Original Tariff
Effective: October 1, 1999

DIRECT ACCESS GENERAL SERVICE

AVAILABILITY

This rate schedule is available in all certificated retail delivery service territory served by Company at all points where facilities of adequate capacity and the required phase and suitable voltage are adjacent to the premises served.

APPLICATION

This rate schedule is applicable to customers receiving electric energy on a direct access basis from any certificated Electric Service Provider (ESP) as defined in A.A.C. R14-2-1603. This rate schedule is applicable to all electric service required when such service is supplied at one point of delivery and measured through one meter. For those customers whose electricity is delivered through more than one meter, service for each meter shall be computed separately under this rate unless conditions in accordance with the Company's Schedule #4 (Totalized Metering of Multiple Service Entrance Sections At a Single Premise for Standard Offer and Direct Access Service) are met. For those service locations where electric service has historically been measured through two meters, when one of the meters was installed pursuant to a water heating rate schedule no longer in effect, the electric service measured by such meters shall be combined for billing purposes.

This rate schedule shall become effective as defined in Company's Terms and Conditions for Direct Access (Schedule #10).

This rate schedule is not applicable to residential service, resale service or direct access service which qualifies for Rate Schedule DA-GS10.

TYPE OF SERVICE

Service shall be single or three phase, 60 Hertz, at one standard voltage as may be selected by customer subject to availability at the customer's premise. Three phase service is furnished under the Company's Conditions Governing Extensions of Electric Distribution Lines and Services (Schedule #3). Transformation equipment is included in cost of extension. Three phase service is not furnished for motors of an individual rated capacity of less than 7-1/2 HP, except for existing facilities or where total aggregate HP of all connected three phase motors exceed 12 HP. Three phase service is required for motors of an individual rated capacity of more than 7-1/2 HP.

METERING REQUIREMENTS

All customers shall comply with the terms and conditions for load profiling or hourly metering specified in the Company's Schedule #10.

MONTHLY BILL

The monthly bill shall be the greater of the amount computed under A. or B. below, including the applicable Adjustments.

A. RATE

June - October Billing Cycles (Summer)

	Basic Delivery Service	Distribution	System Benefits	Competitive Transition Charge
$/month	$12.50			
Per kW over 5		$0.[illegible]		
Per kWh for the first 2,500 kWh		$0.04255		
Per kWh for the next 100 kWh per kW over 5		$0.04255		
Per kWh for the next 42,000 kWh		$0.02901		
Per kWh for all additional kWh		$0.01811		
Per all kWh			$0.00115	
Per all kW				$2.43

(CONTINUED ON REVERSE SIDE)

APPROVED FOR FILING
DECISION #: 61973

ORIGINAL

ON-SITE GENERATION TERMS AND CONDITIONS

Customers served under this rate schedule who have on-site generation connected to the Company's electrical delivery grid shall enter into an Agreement for Interconnection with the Company which shall establish all pertinent details related to interconnection and other required service standards. The Customer does not have the option to sell power and energy to the Company under this tariff.

CONTRACT PERIOD

0 - 1,999 kW:	As provided in Company's standard agreement for service.
2,000 kW and above:	Three (3) years, or longer, at Company's option for initial period when construction is required. One (1) year, or longer, at Company's option when construction is not required.

TERMS AND CONDITIONS

This rate schedule is subject to Company's Terms and Conditions for Standard Offer and Direct Access Service (Schedule #1) and the Company's Schedule #10. These Schedules have provisions that may affect customer's monthly bill.

APPROVED FOR FILING
DECISION #: 61973

ELECTRIC DELIVERY RATES

ARIZONA PUBLIC SERVICE COMPANY
Phoenix, Arizona
Filed by: Alan Propper
Title: Director, Pricing and Regulation

ORIGINAL

A.C.C. No. 5350
Tariff or Schedule No. DA-R1
Original Tariff
Effective: October 1, 1999

DIRECT ACCESS
RESIDENTIAL SERVICE

AVAILABILITY

This rate schedule is available in all certificated retail delivery service territory served by Company and where facilities of adequate capacity and the required phase and suitable voltage are adjacent to the premises served.

APPLICATION

This rate schedule is applicable to customers receiving electric energy on a direct access basis from any certificated Electric Service Provider (ESP) as defined in A.A.C. R14-2-1603. This rate schedule is applicable only to electric delivery required for residential purposes in individual private dwellings and in individually metered apartments when such service is supplied at one point of delivery and measured through one meter. For those dwellings and apartments where electric service has historically been measured through two meters, when one of the meters was installed pursuant to a water heating or space heating rate schedule no longer in effect, the electric service measured by such meters shall be combined for billing purposes.

This rate schedule shall become effective as defined in Company's Terms and Conditions for Direct Access (Schedule #10.)

TYPE OF SERVICE

Service shall be single phase, 60 Hertz, at one standard voltage (120/240 or 120/208 as may be selected by customer subject to availability at the customer's premises). Three phase service is furnished under the Company's Conditions Governing Extensions of Electric Distribution Lines and Services (Schedule #3). Transformation equipment is included in cost of extension. Three phase service is required for motors of an individual rated capacity of 7-1/2 HP or more.

METERING REQUIREMENTS

All customers shall comply with the terms and conditions for load profiling or hourly metering specified in Schedule #10.

MONTHLY BILL

The monthly bill shall be the greater of the amount computed under A or B. below, including the applicable Adjustments.

A. RATE

May - October Billing Cycles (Summer):

	Basic Delivery Service	Distribution	System Benefits	Competitive Transition Charge
$/month	$10.00			
All kWh		$0.04158	$0.00115	$0.00930

November - April Billing Cycles (Winter):

	Basic Delivery Service	Distribution	System Benefits	Competitive Transition Charge
$/month	$10.00			
All kWh		$0.03518	$0.00115	$0.00930

B. MINIMUM $10.00 per month

(CONTINUED ON REVERSE SIDE)

APPROVED FOR FILING
DECISION #: 61973

ELECTRIC DELIVERY RATES

ARIZONA PUBLIC SERVICE COMPANY
Phoenix, Arizona
Filed by: Alan Propper
Title: Director, Pricing and Regulation

ORIGINAL

A.C.C. No. 5352
Tariff or Schedule No. DA-GS10
Original Tariff
Effective: October 1, 1999

DIRECT ACCESS
EXTRA LARGE GENERAL SERVICE

AVAILABILITY

This rate schedule is available in all certificated retail delivery service territory served by Company at all points where facilities of adequate capacity and the required phase and suitable voltage are adjacent to the premises served.

APPLICATION

This rate schedule is applicable to customers receiving electric energy on a direct access basis from any certificated Electric Service Provider (ESP) as defined in A.A.C. R14-2-1603. This rate schedule is applicable only to customers whose monthly maximum demand is 3,000 kW or more for three (3) consecutive months in any continuous twelve (12) month period ending with the current month. Service must be supplied at one point of delivery and measured through one meter unless otherwise specified by individual customer contract. For those customers whose electricity is delivered through more than one meter, service for each meter shall be computed separately under this rate unless conditions in accordance with the Company's Schedule #4 (Totalized Metering of Multiple Service Entrance Sections At a Single Premise for Standard Offer and Direct Access Service) are met.

This rate schedule is not applicable to resale service.

This rate schedule shall become effective as defined in Company's Terms and Conditions for Direct Access (Schedule #10).

TYPE OF SERVICE

Service shall be three phase, 60 Hertz, at Company's standard voltages that are available within the vicinity of customer's premise.

METERING REQUIREMENTS

All customers shall comply with the terms and conditions for hourly metering specified in Schedule #10.

MONTHLY BILL

The monthly bill shall be the greater of the amount computed under A. or B. below, including the applicable Adjustments.

A. RATE

	Basic Delivery Service	Distribution	System Benefits	Competitive Transition Charge
$/month	$2,430.00			
per kW		$3.53		$2.82
per kWh		$0.00999	$0.00115	

PRIMARY AND TRANSMISSION LEVEL SERVICE

1. For customers served at primary voltage (12.5kV to below 69kV), the Distribution charge will be discounted by 4.8%.
2. For customers served at transmission voltage (69kV or higher), the Distribution charge will be discounted 36.7%.
3. Pursuant to A.A.C. R14-2-1612.K.11, the Company shall retain ownership of Current Transformers (CT's) and Potential Transformers (PT's) for those customers taking service at voltage levels of more than 25 kV. For customers whose metering services are provided by an ESP, a monthly facilities charge will be billed, in addition to all other applicable charges shown above, as determined in the service contract based upon the Company's cost of CT and PT ownership, maintenance and operation.

DETERMINATION OF KW

The kW used for billing purposes shall be the greater of:

1. The kW used for billing purposes shall be the average kW supplied during the 15-minute period (or other period as specified by individual customer's contract) of maximum use during the month, as determined from readings of the delivery meter.

2. The minimum kW specified in the agreement for service or individual customer contract.

(CONTINUED ON REVERSE SIDE)

APPROVED FOR FILING
DECISION #: 61973

Exhibit A
DA-GS11

ELECTRIC DELIVERY RATES

ARIZONA PUBLIC SERVICE COMPANY
Phoenix, Arizona
Filed by: Alan Propper
Title: Director, Pricing and Regulation

ORIGINAL

A.C.C. No. 5395
Tariff or Schedule No. DA-GS11
Original Tariff
Effective: October 1, 1999

DIRECT ACCESS
RALSTON PURINA

AVAILABILITY

This rate schedule is available in all certificated retail delivery service territory served by Company at all points where facilities of adequate capacity and the required phase and suitable voltage are adjacent to the premises served.

APPLICATION

This rate schedule is applicable only to Ralston Purina (Site #8639970289) when it receives electric energy on a direct access basis from any certificated Electric Service Provider (ESP) as defined in A.A.C. R14-2-1603. Service must be supplied as specified by individual customer contract and the Company's Schedule #4 (Totalized Metering of Multiple Service Entrance Sections At a Single Premise for Standard Offer and Direct Access Service).

This rate schedule is not applicable to resale service.

This rate schedule shall become effective as defined in Company's Terms and Conditions for Direct Access (Schedule #10).

TYPE OF SERVICE

Service shall be three phase, 60 Hertz, at 12.5 kV.

METERING REQUIREMENTS

Customer shall comply with the terms and conditions for hourly metering specified in Schedule #10.

MONTHLY BILL

The monthly bill shall be the greater of the amount computed under A. or B. below, including the applicable Adjustments.

A. RATE

	Basic Delivery Service	Distribution	System Benefits	Competitive Transition Charge
$/month	$2,430.00			
per kW		$2.58		$1.86
per kWh		$0.00732	$0.00115	

DETERMINATION OF KW

The kW used for billing purposes shall be the greater of:

1. The kW used for billing purposes shall be the average kW supplied during the 15-minute period (or other period as specified by individual customer's contract) of maximum use during the month, as determined from readings of the delivery meter.

2. The minimum kW specified in the agreement for service or individual customer contract.

B. MINIMUM

$2,430.00 per month plus $1.74 per kW per month.

ADJUSTMENTS

1. When Metering, Meter Reading or Consolidated Billing are provided by the Customer's ESP, the monthly bill will be credited as follows:
   Meter $154.15 per month
   Meter Reading $1.69 per month
   Billing $1.33 per month

2. The monthly bill is also subject to the applicable proportionate part of any taxes, or governmental impositions which are or may in the future be assessed on the basis of gross revenues of the Company and/or the price or revenue from the electric service sold and/or the volume of energy delivered or purchased for sale and/or sold hereunder.

(CONTINUED ON REVERSE SIDE)

APPROVED FOR FILING
1/1672

ELECTRIC DELIVERY RATES

ORIGINAL

ARIZONA PUBLIC SERVICE COMPANY
Phoenix, Arizona
Filed by: Alan Propper
Title: Director, Pricing and Regulation

A.C.C. No. 5396
Tariff or Schedule No. DA-GS12
Original Tariff
Effective: October 1, 1999

DIRECT ACCESS
BHP COPPER

AVAILABILITY

This rate schedule is available in all certificated retail delivery service territory served by Company at all points where facilities of adequate capacity and the required phase and suitable voltage are adjacent to the premises served.

APPLICATION

This rate schedule is applicable only to BHP Copper (Site #774932285) when it receives electric energy on a direct access basis from any certificated Electric Service Provider (ESP) as defined in A.A.C. R14-2-1603. Service must be supplied as specified by individual customer contract and the Company's Schedule #4 (Totalized Metering of Multiple Service Entrance Sections At a Single Premise for Standard Offer and Direct Access Service).

This rate schedule is not applicable to resale service.

This rate schedule shall become effective as defined in Company's Terms and Conditions for Direct Access (Schedule #10).

TYPE OF SERVICE

Service shall be three phase, 60 Hertz, at 12.5 kV or higher.

METERING REQUIREMENTS

Customer shall comply with the terms and conditions for hourly metering specified in Schedule #10.

MONTHLY BILL

The monthly bill shall be the greater of the amount computed under A. or B. below, including the applicable Adjustments.

A. RATE

	Basic Delivery Service	Distribution at Primary Voltage	Distribution at Transmission Voltage	System Benefits	Competitive Transition Charge
$/month	$2,430.00				
per kW		$2.35	$1.22		$1.54
per kWh		$0.00665	$0.00346	$0.00115	

PRIMARY AND TRANSMISSION LEVEL SERVICE

Pursuant to A.A.C. R14-2-1612.K.11, the Company shall retain ownership of Current Transformers (CT's) and Potential Transformers (PT's) for those customers taking service at voltage levels of more than 25 kV. For customers whose metering services are provided by an ESP, a monthly facilities charge will be billed, in addition to all other applicable charges shown above, as determined in the service contract based upon the Company's cost of CT and PT ownership, maintenance and operation.

DETERMINATION OF KW

The kW used for billing purposes shall be the greater of:

1. The kW used for billing purposes shall be the average kW supplied during the 30-minute period (or other period as specified by individual customer's contract) of maximum use during the month, as determined from readings of the delivery meter.

2. The minimum kW specified in the agreement for service or individual customer contract.

B. MINIMUM

$2,430.00 per month plus $1.74 per kW per month.

(CONTINUED ON REVERSE SIDE)

APPROVED FOR FILING
DECISION #: 61973

ELECTRIC DELIVERY RATES

ARIZONA PUBLIC SERVICE COMPANY
Phoenix, Arizona
Filed by: Alan Propper
Title: Director, Pricing and Regulation

ORIGINAL

A.C.C. No. 5397
Tariff or Schedule No. DA-GS13
Original Tariff
Effective: October 1, 1999

DIRECT ACCESS
CYPRUS BAGDAD

AVAILABILITY

This rate schedule is available in all certificated retail delivery service territory served by Company at all points where facilities of adequate capacity and the required phase and suitable voltage are adjacent to the premises served.

APPLICATION

This rate schedule is applicable only to Cyprus Bagdad (Site #120932284) when it receives electric energy on a direct access basis from any certificated Electric Service Provider (ESP) as defined in A.A.C. R14-2-1601. Service must be supplied as specified by individual customer contract and the Company's Schedule #4 (Totalized Metering of Multiple Service Entrance Sections At a Single Premise for Standard Offer and Direct Access Service).

This rate schedule is not applicable to resale service.

This rate schedule shall become effective as defined in Company's Terms and Conditions for Direct Access (Schedule #10).

TYPE OF SERVICE

Service shall be three phase, 60 Hertz, at 115 kV or higher.

METERING REQUIREMENTS

Customer shall comply with the terms and conditions for hourly metering specified in Schedule #10.

MONTHLY BILL

The monthly bill shall be the greater of the amount computed under A. or B. below, including the applicable Adjustments.

A. RATE

	Basic Delivery Service	Distribution	System Benefits	Competitive Transition Charge
$ month	$2,430.00			
per kW		$1.05		$1.34
per kWh		$0.00298	$0.00115	

PRIMARY AND TRANSMISSION LEVEL SERVICE

Pursuant to A.A.C. R14-2-1612 K.11, the Company shall retain ownership of Current Transformers (CT's) and Potential Transformers (PT's) for those customers taking service at voltage levels of more than 25 kV. For customers whose metering services are provided by an ESP, a monthly facilities charge will be billed, in addition to all other applicable charges shown above, as determined in the service contract based upon the Company's cost of CT and PT ownership, maintenance and operation.

DETERMINATION OF KW

The kW used for billing purposes shall be the greater of:

1. The kW used for billing purposes shall be the average kW supplied during the 30-minute period (or other period as specified by individual customer's contract) of maximum use during the month, as determined from readings of the delivery meter.

2. The minimum kW specified in the agreement for service or individual customer contract.

B. MINIMUM

$2,430.00 per month plus $1.74 per kW per month, until June 30, 2004 when this minimum will no longer be applicable.

(CONTINUED ON REVERSE SIDE)

APPROVED FOR FILING
DECISION #: 61973

ARIZONA PUBLIC S VICE COMPANY

it A
-/10/99
Schedule A

Competitive Transition Charges
By Direct Access Rate Classes

Line #	Direct Access Rate Class	Competition Transition Charges Effective January 1 of 1999	2000	2001	2002	2003	2004
1	Residential, DA-R1 (per kWh)	$ 0.0093	$ 0.0084	$ 0.0063	$ 0.0056	$ 0.0050	$ 0.0036
2	Under 3 mW, DA-GS1, (per kW/mo.)	$ 2.43	$ 2.20	$ 1.66	$ 1.46	$ 1.30	$ 0.94
3	3 mW and Above, DA-GS10 (per kW/mo.)	$ 2.82	$ 2.55	$ 1.89	$ 1.72	$ 1.51	$ 1.09
4	BHP Copper (per kW/mo.)	$ 1.54	$ 1.53	$ 1.06	$ 0.95	$ 0.83	$ 0.61
5	Cyprus Copper (per kW/mo.)	$ 1.34	$ 1.46	$ 1.05	$ 0.94	$ 0.82	$ 0.61
6	Ralston Purina (per kW/mo.)	$ 1.86	$ 1.98	$ 1.50	$ 1.34	$ 1.18	$ 0.87
7	Average Retail (per kWh)	$ 0.0067	$ 0.0061	$ 0.0054	$ 0.0048	$ 0.0043	$ 0.0031

Charges are based upon recovery of $350 million NPV derived from APS' Compliance Filing of 8/21/98 as adjusted to synchronize Direct Access and Standard Offer revenue decreases.

ARIZONA PUBLIC S[illegible]CE COMPANY

...ibit A
5/13/99
Schedule H

Distribution Charges
By Direct Access Rate Classes

Line #	Direct Access Rate Class	Distribution Charges Effective January 1 of 1999	2000	2001	2002	2003	2004[1]
	Residential, DA-R1						
1	Summer per kWh	$ 0.04158	$ 0.04041	$ 0.03934	$ 0.03837	$ 0.03748	$ 0.03689
2	Winter per kWh	$ 0.03518	$ 0.03419	$ 0.03329	$ 0.03247	$ 0.03172	$ 0.03122
	DA-GS1 (Under 3 mW)						
	Summer Rates						
3	per kW for all kW over 5	$ 0.721	$ 0.691	$ 0.664	$ 0.638	$ 0.615	$ 0.600
4	per kWh for the first 2,500 kWh	$ 0.04255	$ 0.04075	$ 0.03912	$ 0.03763	$ 0.03627	$ 0.03547
5	per kWh for the next 100 kWh per kW over 5	$ 0.04255	$ 0.04075	$ 0.03912	$ 0.03763	$ 0.03627	$ 0.03547
6	per kWh for the next 42,000 kWh	$ 0.02901	$ 0.02779	$ 0.02667	$ 0.02565	$ 0.02473	$ 0.02411
7	per kWh for all additional kWh	$ 0.01811	$ 0.01735	$ 0.01665	$ 0.01602	$ 0.01544	$ 0.01506
	Winter Rates						
8	per kW for all kW over 5	$ 0.652	$ 0.624	$ 0.599	$ 0.576	$ 0.555	$ 0.541
9	per kWh for the first 2,500 kWh	$ 0.03827	$ 0.03666	$ 0.03519	$ 0.03385	$ 0.03263	$ 0.03182
10	per kWh for the next 100 kWh per kW over 5	$ 0.03827	$ 0.03666	$ 0.03519	$ 0.03385	$ 0.03263	$ 0.03182
11	per kWh for the next 42,000 kWh	$ 0.02600	$ 0.02490	$ 0.02390	$ 0.02299	$ 0.02216	$ 0.02161
12	per kWh for all additional kWh	$ 0.01614	$ 0.01546	$ 0.01484	$ 0.01427	$ 0.01376	$ 0.01342
	Voltage Discounts						
13	Primary Voltage	11.6%	12.1%	12.6%	13.1%	13.6%	13.9%
14	Transmission Voltage	52.6%	54.9%	57.2%	59.5%	61.7%	63.3%
	DA-GS10 (3 mW and Above)						
15	per kW	$ 3.53	$ 3.33	$ 3.15	$ 2.98	$ 2.83	$ 2.73
16	per kWh	$ 0.00999	$ 0.00943	$ 0.00892	$ 0.00845	$ 0.00802	$ 0.00774
	Voltage Discounts						
17	Primary Voltage Discount	4.8%	5.1%	5.4%	5.6%	5.9%	6.2%
18	Transmission Voltage Discount	36.7%	38.9%	41.1%	43.4%	45.8%	47.4%
	DA-GS11 (Ralston Purina)						
19	per kW	$ 2.58	$ 2.71	$ 2.57	$ 2.44	$ 2.32	$ 2.25
20	per kWh	$ 0.00712	$ 0.00767	$ 0.00727	$ 0.00691	$ 0.00657	$ 0.00635
	DA-GS12 (BHP Copper)						
21	Primary Voltage Delivery - per kW	$ 2.35	$ 2.30	$ 2.16	$ 2.07	$ 1.99	$ 1.93
22	per kWh	$ 0.00665	$ 0.00651	$ 0.00611	$ 0.00585	$ 0.00561	$ 0.00546
23	Transmission Voltage Delivery - per kW	$ 1.22	$ 1.17	$ 1.03	$ 0.94	$ 0.85	$ 0.80
24	per kWh	$ 0.00346	$ 0.00332	$ 0.00292	$ 0.00266	$ 0.00242	$ 0.00227
	DA-GS13 (Cyprus Bagdad)						
25	per kW	$ 1.05	$ 1.21	$ 1.03	$ 0.94	$ 0.85	$ 0.80
26	per kWh	$ 0.00297	$ 0.00343	$ 0.00292	$ 0.00266	$ 0.00242	$ 0.00227

[1] Transmission voltage customers will not pay Distribution Charges after June 30, 2004

Exhibit A
5/14/99
Schedule C

ARIZONA PUBLIC SERVICE COMPANY

Regulatory Asset Amortization Schedule
(Millions of Dollars)

1999	2000	2001	2002	2003	1/1 - 6/30 2004 [1]	Total [2]
164	158	145	115	86	18	686

[1] Amortization ends 6/30/2004

[2] Includes the disallowance from Section 3.3

ATTACHMENT E

List of County and Municipal Franchises

MUNICIPAL FRANCHISES
(Expiration Date Order)

Municipality Name	Effective Date	Expiration Date
Winkelman	11/25/75	November 25, 2000
Holbrook	4/28/76	April 28, 2001
Prescott	10/11/76	October 11, 2001
Eloy	6/21/77	June 21, 2002
Chandler	7/28/77	July 28, 2002
Gilbert	12/13/77	December 13, 2002
Casa Grande	12/19/77	December 19, 2002
Superior	1/1/78	January 1, 2003
Coolidge	1/13/78	January 13, 2003
Florence	6/1/78	June 1, 2003
Miami	6/19/78	June 19, 2003
Buckeye	5/14/79	May 14, 2004
Prescott Valley	8/9/79	August 9, 2004
Phoenix	10/5/79	October 4, 2004
Winslow	10/23/79	October 23, 2004
El Mirage	3/13/80	March 13, 2005
Scottsdale	3/30/80	March 29, 2005

Municipality Name	Effective Date	Expiration Date
Avondale	4/12/89	April 12, 2005
Goodyear	4/14/80	April 14, 2005
Parker	5/5/80	May 5, 2005
Peoria	/13/80	May 13, 2005
Glendale	6/14/80	June 13, 2005
Wickenburg	9/8/80	September 8, 2005
Snowflake	2/11/81	February 11, 2006
Bisbee	6/30/81	June 30, 2006
San Luis	7/8/81	July 8, 2006
Show Low	11/25/81	Nov. 25, 2006
Douglas	4/27/82	April 27, 2007
Tempe	1/1/82	January 1, 2007
Clarkdale	7/12/84	July 12, 2009
Hayden	3/18/85	March 18, 2010
Carefree	6/5/85	June 5, 2010
Yuma	6/5/90	June 5, 2010
Cottonwood	6/3/86	June 3, 2011
Kearny	6/6/86	June 6, 2011
Youngtown	7/17/86	July 17, 2011

Municipality Name	Effective Date	Expiration Date
Flagstaff	8/21/86	August 21, 2011
Tombstone	10/20/86	October 20, 2011
Camp Verde	11/25/87	Nov. 25, 2012
Surprise	12/17/87	Dec. 17, 2012
Paradise Valley	1/19/88	January 19, 2013
Litchfield Park	3/15/88	March 15, 2013
Cave Creek	12/6/88	December 6, 2013
Gila Bend	12/6/88	December 6, 2013
Globe	8/22/89	August 22, 2014
Quartzsite	3/20/90	March 20, 2015
Sedona	11/19/91	Nov. 19, 2016
Taylor	6/16/92	June 16, 2017
Somerton	4/27/93	April 27, 2018
Chino Valley	03/11/97	March 11, 2022
Payson	5/8/74	May 9, 2024

COUNTY FRANCHISES
(Expiration Date Order)

County Name	Effective Date	Expiration Date
Yavapai	10/24/77	October 24, 2002
Navajo	10/21/80	October 21, 2005
Coconino	5/4/81	May 4, 2006
La Paz	4/23/84	April 23, 2009
Cochise	4/25/88	April 25, 2013
Apache	12/18/89	December 18, 2014
Gila	1/27/92	January 27, 2017
Yuma	10/3/94	October 3, 2019
Pima	12/13/94	December 13, 2019
Pinal	8/27/95	August 27, 2020
Maricopa	9/18/96	September 18, 2021

ATTACHMENT F

Form of Notice

Notice of Filing

UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

Arizona Public Service Company	)	**Docket No. EC00-_____**
Pinnacle West Capital Corporation	)	
Pinnacle West Energy Corporation	)	

NOTICE OF FILING
(____, 2000)

Take notice that on July 28, 2000, Arizona Public Service Corporation ("APS"), Pinnacle West Capital Corporation ("PWCC"), and Pinnacle West Energy Corporation, ("PWE") (collectively, "Applicants"), filed with the Commission an Application for Authorization to Transfer Jurisdictional Facilities under Section 203 of the Federal Power Act, 16 U.S.C. § 824b (1994), and Part 33 of the Federal Energy Regulatory Commission's (FERC or the Commission) Regulations, 18 C.F.R. §§ 33.1-33.10 (1999).

Any person desiring to be heard or to protest said filing should file a motion to intervene or protest with the Federal Energy Regulatory Commission, 888 First Street, N.E., Washington, D.C. 20426, in accordance with Rules 211 and 214 of the Commission's Rules of Practice and Procedures (18 C.F.R. § 385.211 and 18 C.F.R. § 385.214). All such motions or protests should be filed on or before _____, 2000. Protests will be considered by the Commission in determining the appropriate action to be taken, but will not serve to make protestants parties to the proceedings. Any person wishing to become a party must file a motion to intervene. Copies of this filing are on file with the Commission and are available for public inspection. This filing may also be viewed on the Internet at http://www.ferc.fed.us/online/rims.htm (call 202-208-2222 for assistance).

David P. Boergers
Secretary

EXHIBIT A

Resolution of APS's Board of Directors

Applicants have requested a waiver from the requirement to file Exhibit A.

EXHIBIT B

Statement of Measure of Control

The proposed transactions will not create new corporate relationships with third parties. All relevant entities are wholly owned subsidiaries of PWCC, which remains the parent company. These entities include APS, PWE, and APSES. PWCC does not own any bank, trust company, banking association, or firm that is authorized by law to underwrite or participate in the marketing of securities of a public utility, or any company supplying electric equipment to such party.

STATE OF ARIZONA)
) ss.
County of Maricopa)

I, Barbara M. Gomez, Treasurer of Pinnacle West Energy Corporation, do hereby certify that I have read the foregoing Exhibit B to the application of Arizona Public Service Company, Pinnacle West Capital Corporation and Pinnacle West Energy Corporation for approval of transfer of facilities and that the information contained therein is true to the best of my knowledge, information and belief.

Barbara M. Gomez

SUBSCRIBED AND SWORN to before me this 27th day of July, 2000.

Joel R. Spitzkoff
Notary Public

My Commission expires:

June 22, 2003

JOEL R. SPITZKOFF
Notary Public - Arizona
MARICOPA COUNTY
My Commission Expires
JUNE 22, 2003

EXHIBIT C

Balance Sheet

Applicants have requested a waiver from the requirement to file Exhibit C.

EXHIBIT D

Statement of Contingent Liabilities

Applicants have requested a waiver from the requirement to file Exhibit D.

EXHIBIT E

Income Statement

Applicants have requested a waiver from the requirement to file Exhibit E.

EXHIBIT F

Analysis of Retained Earnings

Applicants have requested a waiver from the requirement to file Exhibit F.

EXHIBIT G

Applications Filed With Other Federal and State Regulators

In the event Applicants file their Application with the Nuclear Regulatory Commission ("NRC") for approval to transfer APS's interest in the Palo Verde Nuclear Generating Facility to PWE prior to such time as the Commission has approved the instant Section 203 application, Applicants will submit a copy of the NRC Application to the Commission. Otherwise, Applicants request a waiver from the requirement to file Exhibit G.

EXHIBIT H

Copy of all Contracts Between APS and PWE

Regarding the Proposed Transfer of Assets

As this Application is for an affiliate transfer, APS has not entered into any contracts to sell, lease, or otherwise dispose of the jurisdictional facilities that are the subject of this Application.

STATE OF ARIZONA)
) ss.
County of Maricopa)

I, Barbara M. Gomez, Treasurer of Pinnacle West Energy Corporation, do hereby certify that I have read the foregoing Exhibit H to the application of Arizona Public Service Company, Pinnacle West Capital Corporation and Pinnacle West Energy Corporation for approval of transfer of facilities and that the information contained therein is true to the best of my knowledge, information and belief.

Barbara M. Gomez

SUBSCRIBED AND SWORN to before me this 27th day of July, 2000.

Joel R. Spitzkoff
Notary Public

My Commission expires:

June 22, 2003

JOEL R. SPITZKOFF
Notary Public - Arizona
MARICOPA COUNTY
My Commission Expires
JUNE 22, 2003

APS Electrical Generating System

APS ELECTRICAL GENERATING SYSTEM

	Unit Name	County	Ownership
1	**YUCCA:**	Yuma	
	Combustion Turbine 1		Arizona Public Service
	Combustion Turbine 2		
	Combustion Turbine 3		
	Combustion Turbine 4		
2	**DOUGLAS:**	Cochise	
	Combustion Turbine 1		Arizona Public Service
3	**SAGUARO:**	Pinal	
	Steam Unit 1		Arizona Public Service
	Steam Unit 2		
	Combustion Turbine 1		
	Combustion Turbine 2		
4	**OCOTILLO:**	Maricopa	
	Steam Unit 1		Arizona Public Service
	Steam Unit 2		
	Combustion Turbine 1		
	Combustion Turbine 2		
	Solar 1		
	Solar 2		
5	**WEST PHOENIX:**	Maricopa	
	Steam Unit 4		Arizona Public Service
	Steam Unit 5		
	Steam Unit 6		
	Combustion Turbine 1		
	Combustion Turbine 2		
	Combined Cycle 1		
	Combined Cycle 2		
	Combined Cycle 3		
6	**CHOLLA:**	Navajo	
	Coal Unit 1		Arizona Public Service
	Coal Unit 2		
	Coal Unit 3		
7	**FOUR CORNERS:**	San Juan	
	Coal Unit 1		Arizona Public Service
	Coal Unit 2		
	Coal Unit 3		
	Coal Unit 4		Arizona Public Service, Salt River Project, Tucson Electric Power
	Coal Unit 5		Public Service New Mexico, Southern Cal Edison, El Paso Electric
8	**NAVAJO:**	Coconino	
	Coal Unit 1		Arizona Public Service, Salt River Project, Tucson Electric Power
	Coal Unit 2		Nevada Power, Los Angeles Dept of Water and Power,
	Coal Unit 3		US Government
9	**PALO VERDE:**	Maricopa	
	Nuclear Unit 1		Arizona Public Service, Salt River Project, Southern Cal Public Auth,
	Nuclear Unit 2		Public Service New Mexico, Southern Cal Edison, El Paso Electric,
	Nuclear Unit 3		Los Angeles Dept of Water and Power
10	**COCONINO**	Coconino	
	Solar 1		Arizona Public Service
11	**GLENDALE**	Maricopa	
	Solar 1		Arizona Public Service
12	**SCOTTSDALE**	Maricopa	
	Solar 1		Arizona Public Service

STATE OF ARIZONA)
) ss.
County of Maricopa)

I, Ellen Willhite, Manager, Generation Administration Support, of Arizona Public Service Company, do hereby certify that the foregoing Exhibit I contains an accurate depiction of the facilities that Arizona Public Service is transferring to Pinnacle West Energy Corporation.

Ellen Willhite
Ellen Willhite

SUBSCRIBED AND SWORN to before me this 24 day of July, 2000.

Twyla Hannah
Notary Public

My Commission expires:

OFFICIAL SEAL
TWYLA HANNAH
Notary Public - State of Arizona
MARICOPA COUNTY
My Comm. Expires Nov. 12, 2002

Jana Van Ness
Manager
Regulatory Affairs

Tel 602/250-2310
Fax 602/250-3399
e-mail:jvanness@apsc.com
http://www.apsc.com

Mail Station 9909
P.O. Box 53999
Phoenix, AZ 85072-3999

RECEIVED
1999 DEC -1 P 3:48
AZ CORP COMMISSION
DOCUMENT CONTROL

EXHIBIT D-6

December 1, 1999

Docket Control
Arizona Corporation Commission
1200 West Washington
Phoenix, Arizona 85007

RE: APS Settlement Proceeding
ACC Docket Nos. E-01345A-98-0473, E-01345A-97-0773, RE-00000C-94-0165

Dear Sir or Madam:

Pursuant to the Opinion and Order, Decision No. 61973 in the above referenced Dockets, Arizona Public Service is filing an Addendum to the Settlement Agreement incorporating the modifications required by that Decision. This Addendum has been reviewed and executed by all signatories to the original APS Settlement Agreement.

If you have any questions regarding this filing, please contact me at (602)250-2310.

Sincerely,

Jana Van Ness
Manager
State Regulations

Attachment

Cc: Docket Control (18 copies plus original)
Parties of Record

Addendum to Settlement Agreement

This Addendum is to the Settlement Agreement dated May 14, 1999 (hereafter "Agreement") between Arizona Public Service Company ("APS" or "Company") and the various signatories to the Agreement (collectively with APS, the "Parties"). By signing this Addendum to Settlement Agreement ("Addendum"), the Parties intend to revise certain provisions of the Agreement as directed by the Arizona Corporation Commission ("Commission") in Decision No. 61973 (October 6, 1999) ("Decision"). The Decision adopted and approved the Agreement subject to certain modifications.

I.
Introduction and Recitals

1. On May 14, 1999, the Parties entered into the Agreement;

2. On May 17, 1999, APS filed with the Commission a Notice of Filing Application for Approval of Settlement Agreement and Request for Procedural Order.

3. Commencing on July 14, 1999, and pursuant to a Procedural Order issued by the Hearing Division of the Commission, a full public evidentiary hearing on the Agreement was conducted.

4. On October 6, 1999, the Commission issued its Decision No. 61973 adopting and approving the Agreement as modified in the Decision.

5. The Parties now wish to enter into this Addendum to revise the Agreement as directed in the Decision.

II.
Addendum Agreement

1. Metering, Meter Reading, and Billing Credits

A. The Company's revised unbundled rates and charges reflecting the metering, meter reading, and billing credits required by the Decision are attached hereto as Revised Exhibit A.

B. The revised unbundled rates and charges in Revised Exhibit A to this Addendum are substituted for the corresponding tariffs in Exhibit A to the Agreement.

C. Schedules A through C of Exhibit A to the Agreement are not affected by this Addendum and were adopted and approved by the Commission in the Decision as originally proposed in the Agreement.

2. Advanced Notice for Large Customers. Section 2.3 of the Agreement is replaced with and superceded by the following provision:

> 2.3. Customers greater than 3 MW who choose a direct access supplier must either (a) give APS one year's advance notice before being eligible to return to Standard Offer service, or (b) pay APS for all additional costs incurred as a result of the customer returning to Standard Offer service without providing APS at least one year's advance notice.

3. Deferral of Transfer Costs. Section 2.6(3) of the Agreement is replaced with and superceded by the following provision:

> (3) compliance with the Electric Competition Rules or Commission-ordered programs or directives related to the implementation of the Electric Competition Rules, as they may be amended from time to time, which costs shall be recovered from all customers receiving services from APS, provided however, that no more than sixty-seven percent (67%) of the costs to transfer generation assets to an affiliate or affiliates shall be allowed to be deferred for future collection under this provision; and

4. Rate Matters. Section 2.8 of the Agreement is replaced with and superceded by the following provision:

> 2.8. Neither the Commission nor APS shall be prevented from seeking or authorizing a change in unbundled or Standard Offer rates prior to July 1, 2004, in the event of (a) conditions or circumstances which constitute an emergency, such as an inability to finance on reasonable terms, or (b) material changes in APS' cost of service for Commission-regulated services resulting from federal, tribal, state or local laws, regulatory requirements, judicial decisions, actions or orders. Except for the changes otherwise specifically contemplated by this Agreement, unbundled and Standard Offer rates shall remain unchanged until at least July 1, 2004.

5. Generation Affiliate. Section 4.1 of the Agreement is replaced with and superceded by the following provisions:

4.1. Affiliates.

(1) The Commission will approve the formation of an affiliate or affiliates of APS to acquire at book value the competitive services and assets as currently required by the Electric Competition Rules. In order to facilitate the separation of such assets efficiently and at the lowest possible cost, the Commission shall grant APS a two-year extension of time until December 31, 2002, to accomplish such separation. A similar two-year extension shall be authorized for compliance with A.A.C. R14-2-1606(B).

(2) The affiliate or affiliates formed under this Section 4.1 shall be direct subsidiaries of Pinnacle West Capital Corporation, and not APS.

(3) After the extensions granted in this Section 4.1 have expired, APS shall procure generation for Standard Offer customers from the competitive market as provided for in the Electric Competition Rules. An affiliated generation company formed pursuant to this Section 4.1 may competitively bid for APS' Standard Offer load, but enjoys no automatic privilege outside of the market bid on account of its affiliation with APS.

6. Statutory Waivers. Section 4.3 of the Agreement is deleted in its entirety.

7. Waivers of Affiliate Interest Rules. The Revised Exhibit D to this Addendum setting forth the Affiliate Rules Waivers is substituted for the corresponding Exhibit D to the Agreement so that the proposed waiver of R14-2-804(A) in the Agreement is deleted.

8. Conflicts with Electric Competition Rules. In reliance upon the Commission's directive in Decision No. 61973 (page 9) that "We want to make it clear that the Commission does not intend to revisit the stranded cost portion of the Agreement. It is also not the Commission's intent to undermine the benefits that parties have bargained for," Section 7.1 is replaced with and superseded by the following provision:

> 7.1. Approval of this Agreement by the Commission shall constitute a waiver of any existing Commission order, rule or regulation to the extent necessary to permit performance of the Agreement, as approved by the Commission. Any future Commission order, rule or regulation shall be construed and administered, insofar as possible, in a manner so as not to conflict with the specific provisions of this Agreement, as approved by the Commission. In the event any of the Parties deems a future Commission order, rule or regulation to be inconsistent with the specific provisions of this Agreement, a waiver of the new Commission order, rule or regulation shall be sought.
>
> Nothing in this Agreement is intended to otherwise interfere with the Commission's ability to exercise its regulatory authority by the issuance of orders, rules or regulations. The requirements of this Agreement shall be performed in accordance with the Commission's Electric Competition Rules including any specific waivers granted by the Commission's order approving this Agreement, except where a specific provision of this Agreement would excuse compliance.

9. Interim Code of Conduct. Section 7.7 of the Agreement is replaced with and superceded by the following provision:

> 7.7. Within thirty (30) days of the date of the Commission decision approving this Agreement pursuant to Section 6.1, APS shall file an initial proposed Code of Conduct to address inter-affiliate relationships involving APS as a utility distribution company as required by the Electric Competition Rules and which includes provisions to govern the supply of generation during the two-year extension provided for by Section 4.1 of this Agreement. Interested parties may provide APS with comments on the initial proposed Code of Conduct within sixty (60) days of the date of the Commission decision approving this Agreement. APS will file a final proposed Code of Conduct for Commission approval within ninety (90) days of the date of the Commission decision approving this Agreement. Until the Commission approves a Code of Conduct for APS, APS will voluntarily comply with the initial proposed Code of Conduct or, once filed, the final proposed Code of Conduct.

10. Effect of Addendum. Other than as specifically modified by this Addendum, all provisions of the Agreement remain in full force and effect.

AGREED TO AS OF December 21, **1999:**

RESIDENTIAL UTILITY CONSUMER OFFICE

By Barbara Wytaske

Title Acting Director

ARIZONA PUBLIC SERVICE COMPANY

By Jack Davis

Title President Distribution Svcs.

ARIZONA COMMUNITY ACTION ASSOCIATION

By Betty K Pruitt

Title Acting Executive Director

(Party)

By _____

Title _____

ARIZONANS FOR ELECTRIC CHOICE AND COMPETITION, a coalition of companies and associations in support of competition that includes Cable Systems International, BHP Copper, Motorola, Chemical Lime, Intel, Hughes, Honeywell, Allied Signal, Cyprus Climax Metals, Asarco, Phelps Dodge, Homebuilders of Central Arizona, Arizona Mining Industry Gets Our Support, Arizona Food Marketing Alliance, Arizona Association of Industries, Arizona Multi-housing Association, Arizona Rock Products Association, Arizona Restaurant Association, Arizona Retailers Association, Boeing, Arizona School Board Association, National Federation of Independent Business, Arizona Hospital Association, Lockheed Martin, Abbot Labs and Raytheon.

By _____

Title President

(Party)

By _____

Title _____

Revised
EXHIBIT D
Affiliate Rules Waivers

R14-2-801(5) and R14-2-803, such that the term "reorganization" does not include, and no Commission approval is required for, corporate restructuring that does not directly involve the utility distribution company ("UDC") in the holding company. For example, the holding company may reorganize, form, buy or sell non-UDC affiliates, acquire or divest interests in non-UDC affiliates, etc., without Commission approval.

R14-2-805(A) shall apply only to the UDC

R14-2-805(A)(2)

R14-2-805(A)(6)

R14-2-805(A)(9), (10), and (11)

Recision of Prior Commission Orders

Section X.C of the "Cogeneration and Small Power Production Policy" attached to Decision No. 52345 (July 27, 1981) regarding reporting requirements for cogeneration information.

Decision No. 55118 (July 24, 1986) - Page 15, Lines 5-1/2 through 13-1/2; Finding of Fact No. 24 relating to reporting requirements under the abolished PPFAC.

Decision No. 55818 (December 14, 1987) in its entirety. This decision related to APS Schedule 9 (Industrial Development Rate) which was terminated by the Commission in Decision No. 59329 (October 11, 1995).

9th and 10th Ordering Paragraphs of Decision No. 56450 (April 13, 1989) regarding reporting requirements under the abolished PPFAC.

ELECTRIC DELIVERY RATES

ARIZONA PUBLIC SERVICE COMPANY
Phoenix, Arizona
Filed by: Alan Propper
Title: Director, Pricing and Regulation

ORIGINAL

A.C.C. No. 5351
Tariff or Schedule No. DA-GS1
Original Tariff
Effective: October 1, 1999

DIRECT ACCESS
GENERAL SERVICE

AVAILABILITY

This rate schedule is available in all certificated retail delivery service territory served by Company at all points where facilities of adequate capacity and the required phase and suitable voltage are adjacent to the premises served.

APPLICATION

This rate schedule is applicable to customers receiving electric energy on a direct access basis from any certificated Electric Service Provider (ESP) as defined in A.A.C. R14-2-1603. This rate schedule is applicable to all electric service required when such service is supplied at one point of delivery and measured through one meter. For those customers whose electricity is delivered through more than one meter, service for each meter shall be computed separately under this rate unless conditions in accordance with the Company's Schedule #4 (Totalized Metering of Multiple Service Entrance Sections At a Single Premise for Standard Offer and Direct Access Service) are met. For those service locations where electric service has historically been measured through two meters, when one of the meters was installed pursuant to a water heating rate schedule no longer in effect, the electric service measured by such meters shall be combined for billing purposes.

This rate schedule shall become effective as defined in Company's Terms and Conditions for Direct Access (Schedule #10).

This rate schedule is not applicable to residential service, resale service or direct access service which qualifies for Rate Schedule DA-GS10.

TYPE OF SERVICE

Service shall be single or three phase, 60 Hertz, at one standard voltage as may be selected by customer subject to availability at the customer's premise. Three phase service is furnished under the Company's Conditions Governing Extensions of Electric Distribution Lines and Services (Schedule #3). Transformation equipment is included in cost of extension. Three phase service is not furnished for motors of an individual rated capacity of less than 7-1/2 HP, except for existing facilities or where total aggregate HP of all connected three phase motors exceed 12 HP. Three phase service is required for motors of an individual rated capacity of more than 7-1/2 HP.

METERING REQUIREMENTS

All customers shall comply with the terms and conditions for load profiling or hourly metering specified in the Company's Schedule #10.

MONTHLY BILL

The monthly bill shall be the greater of the amount computed under A. or B. below, including the applicable Adjustments.

A. RATE

June - October Billing Cycles (Summer)

	Basic Delivery Service	Distribution	System Benefits	Competitive Transition Charge
$ month	$12.50			
Per kW over 5		$0.7221		
Per kWh for the first 2,500 kWh		$0.04255		
Per kWh for the next 100 kWh per kW over 5		$0.04255		
Per kWh for the next 42,000 kWh		$0.02901		
Per kWh for all additional kWh		$0.01811		
Per all kWh			$0.00115	
Per all kW				$2.43

(CONTINUED ON REVERSE SIDE)

APPROVED FOR FILING
DECISION #: 61973

A. RATE (continued)

November - May Billing Cycles (Winter):

	Basic Delivery Service	Distribution	System Benefits	Competitive Transition Charge
$/month	$12.50			
Per kW over 5		$0.652		
Per kWh for the first 2,500 kWh		$0.03827		
Per kWh for the next 100 kWh per kW over 5		$0.03827		
Per kWh for the next 42,000 kWh		$0.02600		
Per kWh for all additional kWh		$0.01614		
Per all kWh			$0.00115	
Per all kW				$2.43

PRIMARY AND TRANSMISSION LEVEL SERVICE:

1. For customers served at primary voltage (12.5kV to below 69kV), the Distribution charge will be discounted by 11.6%.
2. For customers served at transmission voltage (69kV or higher), the Distribution charge will be discounted 52.6%.
3. Pursuant to A.A.C. R14-2-1612.K.11, the Company shall retain ownership of Current Transformers (CT's) and Potential Transformers (PT's) for those customers taking service at voltage levels of more than 25kV. For customers whose metering services are provided by an ESP, a monthly facilities charge will be billed, in addition to all other applicable charges shown above, as determined in the service contract based upon the Company's cost of CT and PT ownership, maintenance and operation.

DETERMINATION OF KW

The kW used for billing purposes shall be the average kW supplied during the 15-minute period of maximum use during the month, as determined from readings of the delivery meter.

B. MINIMUM

$12.50 plus $1.74 for each kW in excess of five of either the highest kW established during the 12 months ending with the current month or the minimum kW specified in the agreement for service, whichever is the greater.

ADJUSTMENTS

1. When Metering, Meter Reading or Consolidated Billing are provided by the Customer's ESP, the monthly bill will be credited as follows:
   - Meter $7.62 per month
   - Meter Reading $1.69 per month
   - Billing $1.33 per month
2. The monthly bill is also subject to the applicable proportionate part of any taxes, or governmental impositions which are or may in the future be assessed on the basis of gross revenues of the Company and/or the price or revenue from the electric service sold and/or the volume of energy delivered or purchased for sale and/or sold hereunder.

SERVICES ACQUIRED FROM CERTIFICATED ELECTRIC SERVICE PROVIDERS

Customers served under this rate schedule are responsible for acquiring their own generation and any other required competitively supplied services from an ESP or under the Company's Open Access Transmission Tariff. The Company will provide and bill its transmission and ancillary services on rates approved by the Federal Energy Regulatory Commission to the Scheduling Coordinator who provides transmission service to the Customer's ESP. The Customer's ESP must submit a Direct Access Service Request pursuant to the terms and conditions in Schedule #10

(CONTINUED ON PAGE 3)

APPROVED FOR FILING
DECISION # 61923

ORIGINAL

ON-SITE GENERATION TERMS AND CONDITIONS

Customers served under this rate schedule who have on-site generation connected to the Company's electrical delivery grid shall enter into an Agreement for Interconnection with the Company which shall establish all pertinent details related to interconnection and other required service standards. The Customer does not have the option to sell power and energy to the Company under this tariff.

CONTRACT PERIOD

0 – 1,999 kW:	As provided in Company's standard agreement for service.
2,000 kW and above:	Three (3) years, or longer, at Company's option for initial period when construction is required. One (1) year, or longer, at Company's option when construction is not required.

TERMS AND CONDITIONS

This rate schedule is subject to Company's Terms and Conditions for Standard Offer and Direct Access Service (Schedule #1) and the Company's Schedule #10. These Schedules have provisions that may affect customer's monthly bill.

APPROVED FOR FILING
DECISION #: 61973

ELECTRIC DELIVERY RATES

ARIZONA PUBLIC SERVICE COMPANY
Phoenix, Arizona
Filed by: Alan Propper
Title: Director, Pricing and Regulation

ORIGINAL

A.C.C. No. 5350
Tariff or Schedule No. DA-R1
Original Tariff
Effective: October 1, 1999

DIRECT ACCESS
RESIDENTIAL SERVICE

AVAILABILITY

This rate schedule is available in all certificated retail delivery service territory served by Company and where facilities of adequate capacity and the required phase and suitable voltage are adjacent to the premises served.

APPLICATION

This rate schedule is applicable to customers receiving electric energy on a direct access basis from any certificated Electric Service Provider (ESP) as defined in A.A.C. R14-2-1603. This rate schedule is applicable only to electric delivery required for residential purposes in individual private dwellings and in individually metered apartments when such service is supplied at one point of delivery and measured through one meter. For those dwellings and apartments where electric service has historically been measured through two meters, when one of the meters was installed pursuant to a water heating or space heating rate schedule no longer in effect, the electric service measured by such meters shall be combined for billing purposes.

This rate schedule shall become effective as defined in Company's Terms and Conditions for Direct Access (Schedule #10.)

TYPE OF SERVICE

Service shall be single phase, 60 Hertz, at one standard voltage (120/240 or 120/208 as may be selected by customer subject to availability at the customer's premise). Three phase service is furnished under the Company's Conditions Governing Extensions of Electric Distribution Lines and Services (Schedule #3). Transformation equipment is included in cost of extension. Three phase service is required for motors of an individual rated capacity of 7-1/2 HP or more.

METERING REQUIREMENTS

All customers shall comply with the terms and conditions for load profiling or hourly metering specified in Schedule #10.

MONTHLY BILL

The monthly bill shall be the greater of the amount computed under A. or B. below, including the applicable Adjustments.

A. RATE

May – October Billing Cycles (Summer):

	Basic Delivery Service	Distribution	System Benefits	Competitive Transition Charge
$/month	$10.00			
All kWh		$0.04158	$0.00115	$0.00930

November – April Billing Cycles (Winter):

	Basic Delivery Service	Distribution	System Benefits	Competitive Transition Charge
$/month	$10.00			
All kWh		$0.03518	$0.00115	$0.00930

B. MINIMUM $ 10.00 per month

(CONTINUED ON REVERSE SIDE)

APPROVED FOR FILING
DECISION #: 61973

ADJUSTMENTS

1. When Metering, Meter Reading or Consolidated Billing are provided by the Customer's ESP, the monthly bill will be credited as follows:

Meter	$4.00 per month
Meter Reading	$1.69 per month
Billing	$1.33 per month

2. The monthly bill is also subject to the applicable proportionate part of any taxes, or governmental impositions which are or may in the future be assessed on the basis of gross revenues of the Company and/or the price or revenue from the electric service sold and/or the volume of energy delivered or purchased for sale and/or sold hereunder.

SERVICES ACQUIRED FROM CERTIFICATED ELECTRIC SERVICE PROVIDERS

Customers served under this rate schedule are responsible for acquiring their own generation and any other required competitively supplied services from an ESP. The Company will provide and bill its transmission and ancillary services on rates approved by the Federal Energy Regulatory Commission to the Scheduling Coordinator who provides transmission service to the Customer's ESP. The Customer's ESP must submit a Direct Access Service Request pursuant to the terms and conditions in Schedule #10.

ON-SITE GENERATION TERMS AND CONDITIONS

Customers served under this rate schedule who have on-site generation connected to the Company's electrical delivery grid shall enter into an Agreement for Interconnection with the Company which shall establish all pertinent details related to interconnection and other required service standards. The Customer does not have the option to sell power and energy to the Company under this tariff.

TERMS AND CONDITIONS

This rate schedule is subject to the Company's Terms and Conditions for Standard Offer and Direct Access Services (Schedule #1) and Schedule #10. These schedules have provisions that may affect customer's monthly bill.

APPROVED FOR FILING
DECISION #: 61973

ELECTRIC DELIVERY RATES

ARIZONA PUBLIC SERVICE COMPANY
Phoenix, Arizona
Filed by: Alan Propper
Title: Director, Pricing and Regulation

ORIGINAL

A.C.C. No. 5352
Tariff or Schedule No. DA-GS10
Original Tariff
Effective: October 1, 1999

DIRECT ACCESS
EXTRA LARGE GENERAL SERVICE

AVAILABILITY

This rate schedule is available in all certificated retail delivery service territory served by Company at all points where facilities of adequate capacity and the required phase and suitable voltage are adjacent to the premises served.

APPLICATION

This rate schedule is applicable to customers receiving electric energy on a direct access basis from any certificated Electric Service Provider (ESP) as defined in A.A.C. R14-2-1603. This rate schedule is applicable only to customers whose monthly maximum demand is 3,000 kW or more for three (3) consecutive months in any continuous twelve (12) month period ending with the current month. Service must be supplied at one point of delivery and measured through one meter unless otherwise specified by individual customer contract. For those customers whose electricity is delivered through more than one meter, service for each meter shall be computed separately under this rate unless conditions in accordance with the Company's Schedule #4 (Totalized Metering of Multiple Service Entrance Sections At a Single Premise for Standard Offer and Direct Access Service) are met.

This rate schedule is not applicable to resale service.

This rate schedule shall become effective as defined in Company's Terms and Conditions for Direct Access (Schedule #10).

TYPE OF SERVICE

Service shall be three phase, 60 Hertz, at Company's standard voltages that are available within the vicinity of customer's premise.

METERING REQUIREMENTS

All customers shall comply with the terms and conditions for hourly metering specified in Schedule #10.

MONTHLY BILL

The monthly bill shall be the greater of the amount computed under A. or B. below, including the applicable Adjustments.

A. RATE

	Basic Delivery Service	Distribution	System Benefits	Competitive Transition Charge
$/month	$2,430.00			
per kW		$3.53		$2.82
per kWh		$0.00999	$0.00115	

PRIMARY AND TRANSMISSION LEVEL SERVICE

1. For customers served at primary voltage (12.5kV to below 69kV), the Distribution charge will be discounted by 4.8%.
2. For customers served at transmission voltage (69kV or higher), the Distribution charge will be discounted 36.7%.
3. Pursuant to A.A.C. R14-2-1612.K.11, the Company shall retain ownership of Current Transformers (CT's) and Potential Transformers (PT's) for those customers taking service at voltage levels of more than 25 kV. For customers whose metering services are provided by an ESP, a monthly facilities charge will be billed, in addition to all other applicable charges shown above, as determined in the service contract based upon the Company's cost of CT and PT ownership, maintenance and operation.

DETERMINATION OF KW

The kW used for billing purposes shall be the greater of:

1. The kW used for billing purposes shall be the average kW supplied during the 15-minute period (or other period as specified by individual customer's contract) of maximum use during the month, as determined from readings of the delivery meter.

2. The minimum kW specified in the agreement for service or individual customer contract.

(CONTINUED ON REVERSE SIDE)

APPROVED FOR FILING
DECISION #: 61973

B. MINIMUM

$2,430.00 per month plus $1.74 per kW per month.

ADJUSTMENTS

1. When Metering, Meter Reading or Consolidated Billing are provided by the Customer's ESP, the monthly bill will be credited as follows:

Meter	$154.15 per month
Meter Reading	$1.69 per month
Billing	$1.33 per month

2. The monthly bill is also subject to the applicable proportionate part of any taxes, or governmental impositions which are or may in the future be assessed on the basis of gross revenues of the Company and/or the price or revenue from the electric service sold and/or the volume of energy delivered or purchased for sale and/or sold hereunder.

SERVICES ACQUIRED FROM CERTIFICATED ELECTRIC SERVICE PROVIDERS

Customers served under this rate schedule are responsible for acquiring their own generation and any other required competitively supplied services from an ESP. T he Company will provide and bill its transmission and ancillary services on rates approved by the Federal Energy Regulatory Commission to the Scheduling Coordinator who provides transmission service to the Customer's ESP. The Customer's ESP must submit a Direct Access Service Request pursuant to the terms and conditions in Schedule #10.

ON-SITE GENERATION TERMS AND CONDITIONS

Customers served under this rate schedule who have on-site generation connected to the Company's electrical delivery grid shall enter into an Agreement for Interconnection with the Company which shall establish all pertinent details related to interconnection and other required service standards. The Customer does not have the option to sell power and energy to the Company under this tariff.

CONTRACT PERIOD

For service locations in:

a) Isolated Areas: Ten (10) years, or longer, at Company's option, with standard seven (7) year termination period.
b) Other Areas: Three (3) years, or longer, at Company's option.

TERMS AND CONDITIONS

This rate schedule is subject to Company's Terms and Conditions for Standard Offer and Direct Access Service (Schedule #1) and the Company's Schedule #10. These schedules have provisions that may affect customer's monthly bill.

DECISION # 61973

Exhibit A
DA-GS11

ELECTRIC DELIVERY RATES

ARIZONA PUBLIC SERVICE COMPANY
Phoenix, Arizona
Filed by: Alan Propper
Title: Director, Pricing and Regulation

ORIGINAL

A.C.C. No. 5395
Tariff or Schedule No. DA-GS11
Original Tariff
Effective: October 1, 1999

DIRECT ACCESS
RALSTON PURINA

AVAILABILITY

This rate schedule is available in all certificated retail delivery service territory served by Company at all points where facilities of adequate capacity and the required phase and suitable voltage are adjacent to the premises served.

APPLICATION

This rate schedule is applicable only to Ralston Purina (Site #863970289) when it receives electric energy on a direct access basis from any certificated Electric Service Provider (ESP) as defined in A.A.C. R14-2-1603. Service must be supplied as specified by individual customer contract and the Company's Schedule #4 (Totalized Metering of Multiple Service Entrance Sections At a Single Premise for Standard Offer and Direct Access Service).

This rate schedule is not applicable to resale service.

This rate schedule shall become effective as defined in Company's Terms and Conditions for Direct Access (Schedule #10).

TYPE OF SERVICE

Service shall be three phase, 60 Hertz, at 12.5 kV.

METERING REQUIREMENTS

Customer shall comply with the terms and conditions for hourly metering specified in Schedule #10.

MONTHLY BILL

The monthly bill shall be the greater of the amount computed under A. or B. below, including the applicable Adjustments.

A. RATE

	Basic Delivery Service	Distribution	System Benefits	Competitive Transition Charge
$/month	$2,430.00			
per kW		$2.58		$1.86
per kWh		$0.00732	$0.00115	

DETERMINATION OF KW

The kW used for billing purposes shall be the greater of

1. The kW used for billing purposes shall be the average kW supplied during the 15-minute period (or other period as specified by individual customer's contract) of maximum use during the month, as determined from readings of the delivery meter.

2. The minimum kW specified in the agreement for service or individual customer contract.

B. MINIMUM

$2,430.00 per month plus $1.74 per kW per month.

ADJUSTMENTS

1. When Metering, Meter Reading or Consolidated Billing are provided by the Customer's ESP, the monthly bill will be credited as follows:

Meter	$154.15 per month
Meter Reading	$1.69 per month
Billing	$1.33 per month

2. The monthly bill is also subject to the applicable proportionate part of any taxes, or governmental impositions which are or may in the future be assessed on the basis of gross revenues of the Company and/or the price or revenue from the electric service sold and/or the volume of energy delivered or purchased for sale and/or sold hereunder.

(CONTINUED ON REVERSE SIDE)

APPROVED FOR FILING
DECISION # 61973

SERVICES ACQUIRED FROM CERTIFICATED ELECTRIC SERVICE PROVIDERS

Customer is responsible for acquiring its own generation and any other required competitively supplied services from an ESP. The Company will provide and bill its transmission and ancillary services on rates approved by the Federal Energy Regulatory Commission to the Scheduling Coordinator who provides transmission service to the Customer's ESP. The Customer's ESP must submit a Direct Access Service Request pursuant to the terms and conditions in Schedule #10.

ON-SITE GENERATION TERMS AND CONDITIONS

If Customer has on-site generation connected to the Company's electrical delivery grid, it shall enter into an Agreement for Interconnection with the Company which shall establish all pertinent details related to interconnection and other required service standards. The Customer does not have the option to sell power and energy to the Company under this tariff.

TERMS AND CONDITIONS

This rate schedule is subject to Company's Terms and Conditions for Standard Offer and Direct Access Service (Schedule #1) and the Company's Schedule #10. These schedules have provisions that may affect customer's monthly bill.

APPROVED AS TO FILING
DECISION # 61973

ELECTRIC DELIVERY RATES

ORIGINAL

ARIZONA PUBLIC SERVICE COMPANY
Phoenix, Arizona
Filed by: Alan Propper
Title: Director, Pricing and Regulation

A.C.C. No. 5396
Tariff or Schedule No. DA-GS12
Original Tariff
Effective: October 1, 1999

DIRECT ACCESS
BHP COPPER

AVAILABILITY

This rate schedule is available in all certificated retail delivery service territory served by Company at all points where facilities of adequate capacity and the required phase and suitable voltage are adjacent to the premises served.

APPLICATION

This rate schedule is applicable only to BHP Copper (Site #774932285) when it receives electric energy on a direct access basis from any certificated Electric Service Provider (ESP) as defined in A.A.C. R14-2-1603. Service must be supplied as specified by individual customer contract and the Company's Schedule #4 (Totalized Metering of Multiple Service Entrance Sections At a Single Premise for Standard Offer and Direct Access Service).

This rate schedule is not applicable to resale service.

This rate schedule shall become effective as defined in Company's Terms and Conditions for Direct Access (Schedule #10).

TYPE OF SERVICE

Service shall be three phase, 60 Hertz, at 12.5 kV or higher.

METERING REQUIREMENTS

Customer shall comply with the terms and conditions for hourly metering specified in Schedule #10.

MONTHLY BILL

The monthly bill shall be the greater of the amount computed under A. or B. below, including the applicable Adjustments.

A. RATE

	Basic Delivery Service	Distribution at Primary Voltage	Distribution at Transmission Voltage	System Benefits	Competitive Transition Charge
$/month	$2,430.00				
per kW		$2.35	$1.22		$1.54
per kWh		$0.00665	$0.00346	$0.00115	

PRIMARY AND TRANSMISSION LEVEL SERVICE:

Pursuant to A.A.C. R14-2-1612.K.11, the Company shall retain ownership of Current Transformers (CT's) and Potential Transformers (PT's) for those customers taking service at voltage levels of more than 25 kV. For customers whose metering services are provided by an ESP, a monthly facilities charge will be billed, in addition to all other applicable charges shown above, as determined in the service contract based upon the Company's cost of CT and PT ownership, maintenance and operation.

DETERMINATION OF KW

The kW used for billing purposes shall be the greater of:

1. The kW used for billing purposes shall be the average kW supplied during the 30-minute period (or other period as specified by individual customer's contract) of maximum use during the month, as determined from readings of the delivery meter.

2. The minimum kW specified in the agreement for service or individual customer contract.

B. MINIMUM

$2,430.00 per month plus $1.74 per kW per month.

(CONTINUED ON REVERSE SIDE)

APPROVED FOR FILING
DECISION #: 61973

ADJUSTMENTS

1. When Metering, Meter Reading or Consolidated Billing are provided by the Customer's ESP, the monthly bill will be credited as follows:

Meter	$154.15 per month
Meter Reading	$1.69 per month
Billing	$1.33 per month

2. The monthly bill is also subject to the applicable proportionate part of any taxes, or governmental impositions which are or may in the future be assessed on the basis of gross revenues of the Company and/or the price or revenue from the electric service sold and/or the volume of energy delivered or purchased for sale and/or sold hereunder.

SERVICES ACQUIRED FROM CERTIFICATED ELECTRIC SERVICE PROVIDERS

Customer is responsible for acquiring its own generation and any other required competitively supplied services from an ESP. The Company will provide and bill its transmission and ancillary services on rates approved by the Federal Energy Regulatory Commission to the Scheduling Coordinator who provides transmission service to the Customer's ESP. The Customer's ESP must submit a Direct Access Service Request pursuant to the terms and conditions in Schedule #10.

ON-SITE GENERATION TERMS AND CONDITIONS

If Customer has on-site generation connected to the Company's electrical delivery grid, it shall enter into an Agreement for Interconnection with the Company which shall establish all pertinent details related to interconnection and other required service standards. The Customer does not have the option to sell power and energy to the Company under this tariff.

TERMS AND CONDITIONS

This rate schedule is subject to Company's Terms and Conditions for Standard Offer and Direct Access Service (Schedule #1) and the Company's Schedule #10. These schedules have provisions that may affect customer's monthly bill.

ARIZONA FOR FILING
DECISION #: 61973

ELECTRIC DELIVERY RATES

ARIZONA PUBLIC SERVICE COMPANY
Phoenix, Arizona
Filed by: Alan Propper
Title: Director, Pricing and Regulation

ORIGINAL

A.C.C. No. 5397
Tariff or Schedule No. DA-GS13
Original Tariff
Effective: October 1, 1999

DIRECT ACCESS
CYPRUS BAGDAD

AVAILABILITY

This rate schedule is available in all certificated retail delivery service territory served by Company at all points where facilities of adequate capacity and the required phase and suitable voltage are adjacent to the premises served.

APPLICATION

This rate schedule is applicable only to Cyprus Bagdad (Site #120932284) when it receives electric energy on a direct access basis from any certificated Electric Service Provider (ESP) as defined in A.A.C. R14-2-1603. Service must be supplied as specified by individual customer contract and the Company's Schedule #4 (Totalized Metering of Multiple Service Entrance Sections At a Single Premise for Standard Offer and Direct Access Service).

This rate schedule is not applicable to resale service.

This rate schedule shall become effective as defined in Company's Terms and Conditions for Direct Access (Schedule #10).

TYPE OF SERVICE

Service shall be three phase, 60 Hertz, at 115 kV or higher.

METERING REQUIREMENTS

Customer shall comply with the terms and conditions for hourly metering specified in Schedule #10.

MONTHLY BILL

The monthly bill shall be the greater of the amount computed under A. or B. below, including the applicable Adjustments.

A. RATE

	Basic Delivery Service	Distribution	System Benefits	Competitive Transition Charge
$/month	$2,430.00			
per kW		$1.05		$1.34
per kWh		$0.00298	$0.00115	

PRIMARY AND TRANSMISSION LEVEL SERVICE:

Pursuant to A.A.C. R14-2-1612.K.11, the Company shall retain ownership of Current Transformers (CT's) and Potential Transformers (PT's) for those customers taking service at voltage levels of more than 25 kV. For customers whose metering services are provided by an ESP, a monthly facilities charge will be billed, in addition to all other applicable charges shown above, as determined in the service contract based upon the Company's cost of CT and PT ownership, maintenance and operation.

DETERMINATION OF KW

The kW used for billing purposes shall be the greater of:

1. The kW used for billing purposes shall be the average kW supplied during the 30-minute period (or other period as specified by individual customer's contract) of maximum use during the month, as determined from readings of the delivery meter.

2. The minimum kW specified in the agreement for service or individual customer contract.

B. MINIMUM

$2,430.00 per month plus $1.74 per kW per month, until June 30, 2004 when this minimum will no longer be applicable.

(CONTINUED ON REVERSE SIDE)

APPROVED FOR FILING
DECISION #: 61973

ADJUSTMENTS

1. When Metering, Meter Reading or Consolidated Billing are provided by the Customer's ESP, the monthly bill will be credited as follows:

Meter	$154.15 per month
Meter Reading	$1.69 per month
Billing	$1.33 per month

2. The monthly bill is also subject to the applicable proportionate part of any taxes, or governmental impositions which are or may in the future be assessed on the basis of gross revenues of the Company and/or the price or revenue from the electric service sold and/or the volume of energy delivered or purchased for sale and/or sold hereunder.

SERVICES ACQUIRED FROM CERTIFICATED ELECTRIC SERVICE PROVIDERS

Customer is responsible for acquiring its own generation and any other required competitively supplied services from an ESP. The Company will provide and bill its transmission and ancillary services on rates approved by the Federal Energy Regulatory Commission to the Scheduling Coordinator who provides transmission service to the Customer's ESP. The Customer's ESP must submit a Direct Access Service Request pursuant to the terms and conditions in Schedule #10.

ON-SITE GENERATION TERMS AND CONDITIONS

If Customer has on-site generation connected to the Company's electrical delivery grid, it shall enter into an Agreement for Interconnection with the Company which shall establish all pertinent details related to interconnection and other required service standards. The Customer does not have the option to sell power and energy to the Company under this tariff.

TERMS AND CONDITIONS

This rate schedule is subject to Company's Terms and Conditions for Standard Offer and Direct Access Service (Schedule #1) and the Company's Schedule #10. These schedules have provisions that may affect customer's monthly bill.

APPROVED FOR FILING
DECISION #: 61973

ARIZONA PUBLIC S VICE COMPANY

Competitive Transition Charges
By Direct Access Rate Classes

...it A
.../10/99
Schedule A

Line #	Direct Access Rate Class	Competition Transition Charges Effective January 1 of					
		1999	2000	2001	2002	2003	2004
1	Residential, DA-R1 (per kWh)	$ 0.0093	$ 0.0084	$ 0.0063	$ 0.0056	$ 0.0050	$ 0.0036
2	Under 3 mW, DA-GS1, (per kW/mo.)	$ 2.43	$ 2.20	$ 1.66	$ 1.46	$ 1.30	$ 0.94
3	3 mW and Above, DA-GS10 (per kW/mo.)	$ 2.82	$ 2.55	$ 1.89	$ 1.72	$ 1.51	$ 1.09
4	BHP Copper (per kW/mo.)	$ 1.54	$ 1.53	$ 1.06	$ 0.95	$ 0.83	$ 0.61
5	Cyprus Copper (per kW/mo.)	$ 1.34	$ 1.46	$ 1.05	$ 0.94	$ 0.82	$ 0.61
6	Ralston Purina (per kW/mo.)	$ 1.86	$ 1.98	$ 1.50	$ 1.34	$ 1.18	$ 0.87
7	Average Retail (per kWh)	$ 0.0067	$ 0.0061	$ 0.0054	$ 0.0048	$ 0.0043	$ 0.0031

Charges are based upon recovery of $350 million NPV derived from APS' Compliance Filing of 8/21/98 as adjusted to synchronize Direct Access and Standard Offer revenue decreases.

ARIZONA PUBLIC S[illegible]CE COMPANY

...ibit A
5/13/99
Schedule B

Distribution Charges
By Direct Access Rate Classes

Line #	Direct Access Rate Class	Distribution Charges Effective January 1 of 1999	2000	2001	2002	2003	2004[1]
	Residential, DA-R1						
1	Summer per kWh	$ 0.04158	$ 0.04041	$ 0.03934	$ 0.03837	$ 0.03748	$ 0.03689
2	Winter per kWh	$ 0.03518	$ 0.03419	$ 0.03329	$ 0.03247	$ 0.03172	$ 0.03122
	DA-GS1 (Under 3 mW)						
	Summer Rates						
3	per kW for all kW over 5	$ 0.721	$ 0.691	$ 0.663	$ 0.638	$ 0.615	$ 0.600
4	per kWh for the first 2,500 kWh	$ 0.04255	$ 0.04075	$ 0.03912	$ 0.03763	$ 0.03627	$ 0.03537
5	per kWh for the next 100 kWh per kW over 5	$ 0.04255	$ 0.04075	$ 0.03912	$ 0.03763	$ 0.03627	$ 0.03537
6	per kWh for the next 42,000 kWh	$ 0.02901	$ 0.02779	$ 0.02667	$ 0.02565	$ 0.02473	$ 0.02411
7	per kWh for all additional kWh	$ 0.01811	$ 0.01735	$ 0.01665	$ 0.01602	$ 0.01544	$ 0.01506
	Winter Rates						
8	per kW for all kW over 5	$ 0.652	$ 0.624	$ 0.599	$ 0.576	$ 0.555	$ 0.541
9	per kWh for the first 2,500 kWh	$ 0.03827	$ 0.03666	$ 0.03519	$ 0.03385	$ 0.03263	$ 0.03182
10	per kWh for the next 100 kWh per kW over 5	$ 0.03827	$ 0.03666	$ 0.03519	$ 0.03385	$ 0.03263	$ 0.03182
11	per kWh for the next 42,000 kWh	$ 0.02600	$ 0.02490	$ 0.02390	$ 0.02299	$ 0.02216	$ 0.02161
12	per kWh for all additional kWh	$ 0.01614	$ 0.01546	$ 0.01484	$ 0.01427	$ 0.01376	$ 0.01342
	Voltage Discounts						
13	Primary Voltage	11.6%	12.1%	12.6%	13.1%	13.6%	13.9%
14	Transmission Voltage	52.6%	54.9%	57.2%	59.5%	61.7%	63.3%
	DA-GS10 (3 mW and Above)						
15	per kW	$ 3.53	$ 3.33	$ 3.15	$ 2.98	$ 2.83	$ 2.73
16	per kWh	$ 0.00999	$ 0.00943	$ 0.00892	$ 0.00845	$ 0.00802	$ 0.00774
	Voltage Discounts						
17	Primary Voltage Discount	4.8%	5.1%	5.4%	5.6%	5.9%	6.2%
18	Transmission Voltage Discount	36.7%	38.9%	41.1%	43.4%	45.8%	47.4%
	DA-GS11 (Ralston Purina)						
19	per kW	$ 2.58	$ 2.71	$ 2.57	$ 2.44	$ 2.32	$ 2.25
20	per kWh	$ 0.00732	$ 0.00767	$ 0.00727	$ 0.00691	$ 0.00657	$ 0.00635
	DA-GS12 (IBHP Copper)						
21	Primary Voltage Delivery - per kW	$ 2.35	$ 2.30	$ 2.16	$ 2.07	$ 1.99	$ 1.93
22	per kWh	$ 0.00665	$ 0.00651	$ 0.00611	$ 0.00585	$ 0.00561	$ 0.00546
23	Transmission Voltage Delivery - per kW	$ 1.22	$ 1.17	$ 1.03	$ 0.94	$ 0.85	$ 0.80
24	per kWh	$ 0.00346	$ 0.00332	$ 0.00292	$ 0.00266	$ 0.00242	$ 0.00227
	DA-GS13 (Cyprus Bagdad)						
25	per kW	$ 1.05	$ 1.21	$ 1.03	$ 0.94	$ 0.85	$ 0.80
26	per kWh	$ 0.00297	$ 0.00343	$ 0.00292	$ 0.00266	$ 0.00242	$ 0.00227

[1] Transmission voltage customers will not pay Distribution Charges after June 30, 2004

Exhibit A
5/14/99
Schedule C

ARIZONA PUBLIC SERVICE COMPANY

Regulatory Asset Amortization Schedule
(Millions of Dollars)

1999	2000	2001	2002	2003	1/1 - 6/30 2004 [1/]	Total [2/]
164	158	145	115	86	18	686

[1/] Amortization ends 6/30/2004

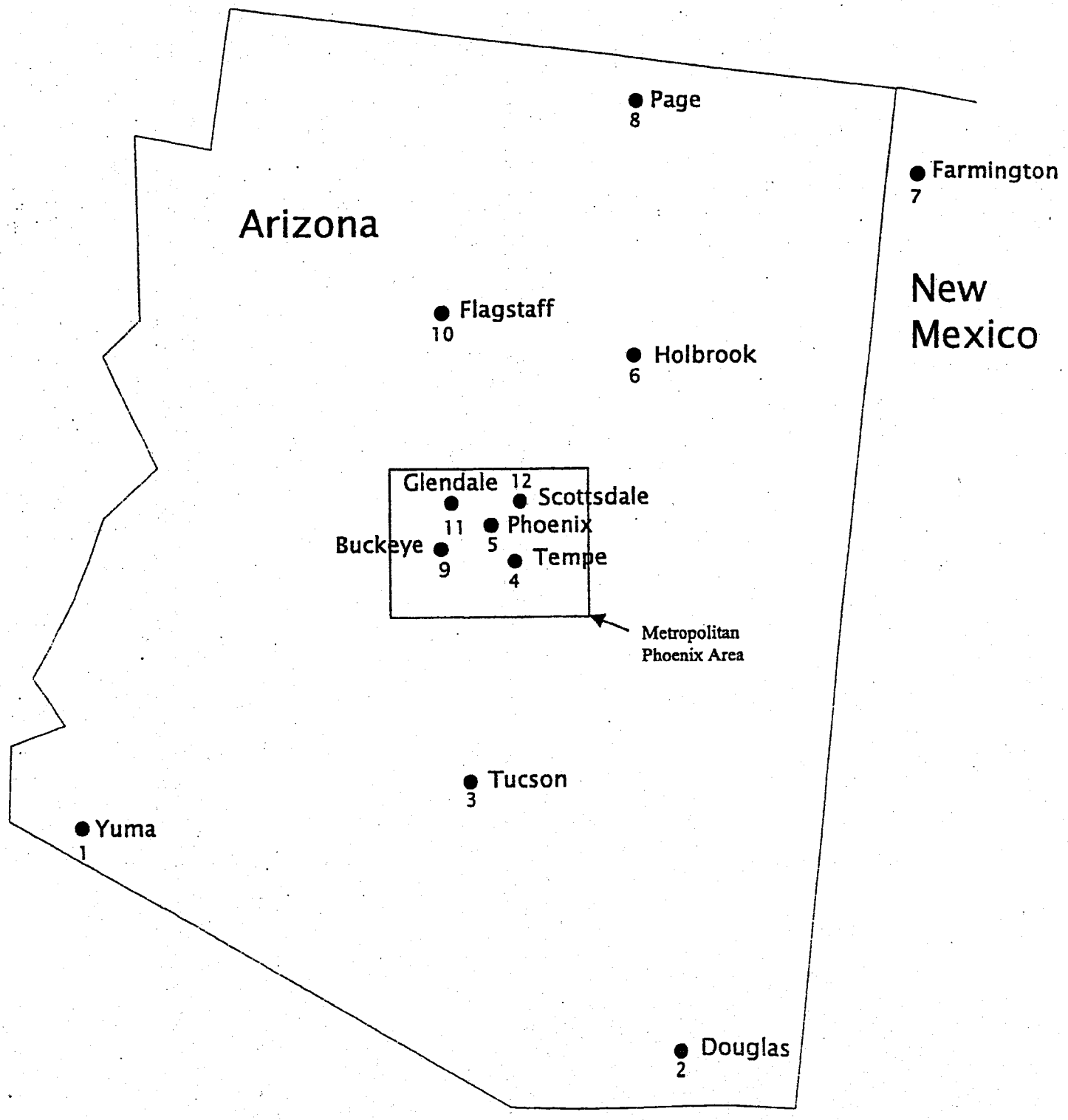
[2/] Includes the disallowance from Section 3.3

APS
Arizona Public Service Company

COMPANY CORRESPONDENCE

Bcc: Snell & Wilmer (3)
Becky Hickman (3)
Don Robertson
Jack Davis
Bill Post
Alan Propper
Jana Van Ness
Barbara Klemstine
Keith Van Ausdal
Warren Kotzman
Sally Stewart
Colleen Hawk
Wayne Ettenborough
Sharon Madden

APS Electrical Generating System



APS ELECTRICAL GENERATING SYSTEM

	Unit Name	County	Ownership
1	**YUCCA:** Combustion Turbine 1 Combustion Turbine 2 Combustion Turbine 3 Combustion Turbine 4	Yuma	Arizona Public Service
2	**DOUGLAS:** Combustion Turbine 1	Cochise	Arizona Public Service
3	**SAGUARO:** Steam Unit 1 Steam Unit 2 Combustion Turbine 1 Combustion Turbine 2	Pinal	Arizona Public Service
4	**OCOTILLO:** Steam Unit 1 Steam Unit 2 Combustion Turbine 1 Combustion Turbine 2 Solar 1 Solar 2	Maricopa	Arizona Public Service
5	**WEST PHOENIX:** Steam Unit 4 Steam Unit 5 Steam Unit 6 Combustion Turbine 1 Combustion Turbine 2 Combined Cycle 1 Combined Cycle 2 Combined Cycle 3	Maricopa	Arizona Public Service
6	**CHOLLA:** Coal Unit 1 Coal Unit 2 Coal Unit 3	Navajo	Arizona Public Service
7	**FOUR CORNERS:** Coal Unit 1 Coal Unit 2 Coal Unit 3 Coal Unit 4 Coal Unit 5	San Juan	Arizona Public Service Arizona Public Service, Salt River Project, Tucson Electric Power Public Service New Mexico, Southern Cal Edison, El Paso Electric
8	**NAVAJO:** Coal Unit 1 Coal Unit 2 Coal Unit 3	Coconino	Arizona Public Service, Salt River Project, Tucson Electric Power Nevada Power, Los Angeles Dept of Water and Power, US Government
9	**PALO VERDE:** Nuclear Unit 1 Nuclear Unit 2 Nuclear Unit 3	Maricopa	Arizona Public Service, Salt River Project, Southern Cal Public Auth, Public Service New Mexico, Southern Cal Edison, El Paso Electric, Los Angeles Dept of Water and Power
10	**COCONINO** Solar 1	Coconino	Arizona Public Service
11	**GLENDALE** Solar 1	Maricopa	Arizona Public Service
12	**SCOTTSDALE** Solar 1	Maricopa	Arizona Public Service

STATE OF ARIZONA)
) ss.
County of Maricopa)

I, Ellen Willhite, Manager, Generation Administration Support, of Arizona Public Service Company, do hereby certify that the foregoing Exhibit I contains an accurate depiction of the facilities that Arizona Public Service is transferring to Pinnacle West Energy Corporation.

Ellen Willhite
Ellen Willhite

SUBSCRIBED AND SWORN to before me this 24 day of July, 2000.

Twyla Hannah
Notary Public

My Commission expires:

OFFICIAL SEAL
TWYLA HANNAH
Notary Public - State of Arizona
MARICOPA COUNTY
My Comm. Expires Nov. 12, 2002

EXHIBIT H-1

PROPOSED FORM OF FEDERAL REGISTER NOTICE

SECURITIES AND EXCHANGE COMMISSION
(Release No. 35-_____)

Filings under the Public Utility Holding Company Act of 1935, as amended ("Act")

September __, 2000

Notice is hereby given that the following filing(s) has/have been made with the Commission pursuant to provisions of the Act and rules promulgated thereunder. All interested persons are referred to the application(s) and/or declaration(s) for the complete statements of the proposed transaction(s) summarized below. The application(s) and declaration(s) and any amendments thereto is/are available for public inspection through the Commission's Office of Public Reference.

Interested persons wishing to comment or request a hearing on the application(s) and/or declaration(s) should submit their views in writing by September __, 2000, to the Secretary, Securities and Exchange Commission, Washington, D.C. 20549-0609, and serve a copy on the relevant applicant(s) and/or declarant(s) at the address(es) specified below. Proof of service (by affidavit or, in case of an attorney at law, by certificate) should be filed with the request. Any request for hearing shall identify specifically the issues of fact or law that are disputed. A person who so requests will be so notified of any hearing, if ordered, and will receive a copy of any notice or order issued in the matter. After September __, 2000, the application(s) and/or declaration(s), as filed or amended, may be granted and/or permitted to become effective.

****

Pinnacle West Capital Corporation ("PNW"), 400 North Fifth Street, Phoenix, Arizona 85004, has filed an application-declaration pursuant to Sections 9(a)(2) and 10 of the Act, in which it requests approval to establish a new public-utility company subsidiary in connection with the proposed corporate reorganization ("Reorganization"), involving the relocation of certain generation assets from Arizona Public Service Company ("APS"), PNW's existing public-utility company subsidiary, to Pinnacle West Energy Corporation ("PWE"), another wholly-owned subsidiary of PNW. As a result of this Reorganization, PWE will become an "electric utility company" and a "public-utility company" within the meaning of the Act, and PNW will acquire an additional public-utility subsidiary. PNW will continue to meet the requirements for an intrastate exemption under Section 3(a)(1) of the Act and to file annual exemption statements on Form U-3A-2 pursuant to Rule 2 of the Commission's regulations.

The purpose of the reorganization is to comply with certain requirements set forth in rules adopted by the Arizona Corporation Commission ("ACC") that provide the framework for

introduction of retail electric competition in Arizona ("Competition Rules"), and in a final ACC order approving APS's settlement with various parties and the ACC with respect to implementation of the Competition Rules (the "Settlement"). Pursuant to the Competition Rules and Settlement, APS must move all of its generating assets and competitive services to PNW subsidiaries no later than December 31, 2002.

PNW was incorporated in 1985 under the laws of the State of Arizona. Through its subsidiaries, PNW is engaged in the generation, transmission, and distribution of electricity and the sale of energy services. Through subsidiaries, PNW is also involved in real estate development and in venture capital investment. PNW's principal subsidiaries are: APS, PWE, APS Energy Services Company, Inc., SunCor Development Company, and El Dorado Investment Company.

PNW's principal public-utility subsidiary is APS. APS, incorporated in 1920 under the laws of the State of Arizona, is a wholly-owned subsidiary of PNW. APS's principal executive offices are located at 400 North Fifth Street, Phoenix Arizona 85004. APS provides retail electric services principally in the State of Arizona and is actively engaged in the competitive wholesale electric markets. APS is subject to regulation by the ACC with respect to retail rates, accounting, service standards, service territory, issuances of securities, certification of generation and transmission projects and various other matters. APS currently owns generating facilities with a total accredited capacity of approximately 4,100 megawatts.

APS also owns and operates approximately 4,853 miles of transmission lines, of which all but 140 miles are located within the State of Arizona. APS's transmission was built primarily to bring generation from its power plants to its retail electric loads in Arizona. As of December 31, 1999, APS's distribution system served approximately 827,000 electric retail customers in its service territory within the State of Arizona. APS provides distribution services in 11 of Arizona's 15 counties, including the metropolitan Phoenix area. Pursuant to the Settlement approved by the ACC in 1999, retail rates have been set until July 1, 2004, subject to conditions or circumstances which constitute an emergency.

PWE, another wholly-owned subsidiary of PNW, was incorporated in 1999 under the laws of the State of Arizona. PWE was organized primarily to engage in the business of developing, owning, and operating generation plants used for the production and sale of wholesale energy. Currently, PWE is engaged in the development of approximately 2,600 megawatts of generating capacity in the State of Arizona; however, PWE is not currently an electric utility company or a public-utility company within the meaning of the Act. Upon completion of the Reorganization, PWE will own or lease the generation facilities currently owned or leased by APS and will assume APS's responsibilities as operator of the facilities.

When the Reorganization is complete, APS's existing structure, in which its electric utility operations are divided along functional lines, will be formalized and separate corporate entities will engage in the transmission/distribution of electricity and the generation of electricity. APS will continue to own and operate its existing electric transmission/distribution system, and PWE will own or lease and operate APS's existing generation assets, selling the output from these assets to PNW's

power marketing and trading division and to other wholesale entities. In addition, APS will serve as the provider of last resort to standard offer customers in APS's existing service territory.

The generation assets will be moved to PWE at book value. In addition, PWE will assume certain outstanding debt associated with the generating assets being moved. Specifically, PWE will assume APS's rights and obligations with respect to approximately $180 million in pollution control bonds.

The principal purpose of the Reorganization is to assure compliance with the provisions of the Competition Rules and the Settlement and to provide PNW with increased financial, managerial, and organizational flexibility which will enable APS and PWE to compete more effectively in a restructured utility industry. It is stated that the Reorganization will lead to a clear, functional and corporate separation between PNW's generation business and its wires business, enabling each company to focus its resources on more clearly defined product markets and services. PNW also states that the Reorganization will have no adverse effect on APS's existing electric utility operations. The Reorganization will not result in any real change in the ultimate ownership of existing utility assets nor will it result in the transfer or acquisition of any additional utility assets beyond those currently held by APS or being developed by PWE.

PNW states that the proposed transaction will satisfy the requirements of Section 9(a)(2), as well as the relevant provisions of Section 10 of the Act. PNW will continue to claim an exemption pursuant to Section 3(a)(1) and Rule 2 thereunder.

File No. 070-09745

UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
WASHINGTON, D.C. 20549

AMENDMENT NO. 1
TO
FORM U-1
APPLICATION
UNDER
THE PUBLIC UTILITY HOLDING COMPANY ACT OF 1935

PINNACLE WEST CAPITAL CORPORATION
400 East Van Buren Street, Suite 700
Phoenix, Arizona 85004

(Name of company filing this statement and address of principal executive office)

None

(Name of top registered holding company parent)

Herbert I. Zinn
Pinnacle West Capital Corporation
400 North Fifth Street
Mail Station 8695
Phoenix, Arizona 85004

Mary Ann K. Huntington
Morgan, Lewis & Bockius LLP
1800 M Street, N.W.
Washington, D.C. 20036

(Name and address of agents for service)

The Commission is requested to send copies of all notices, orders, and communications in connection with this Application to:

Herbert I. Zinn
Pinnacle West Capital Corporation
400 North Fifth Street
Mail Station 8695
Phoenix, Arizona 85004

Mary Ann K. Huntington
Morgan, Lewis & Bockius LLP
1800 M Street, N.W.
Washington, D.C. 20036

This Amendment No. 1 is being filed in order to provide the Securities and Exchange Commission with copies of Exhibit No. D-2 (Order of FERC) and Exhibit No. F-1 (Signed Initial Opinions of Counsel).

Signature

Pursuant to the requirements of the Public Utility Holding Company Act of 1935, as amended, the undersigned company has duly caused this statement to be signed on its behalf by the undersigned thereunto duly authorized.

Pinnacle West Capital Corporation

Barbara M. Gomez

By: Barbara M. Gomez
Its: Treasurer

Dated: December 8, 2000
Phoenix, Arizona

Exhibit D-2

93 FERC ¶ 61,216

UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

Before Commissioners: James J. Hoecker, Chairman;
William L. Massey, Linda Breathitt,
and Curt Hébert, Jr.

Arizona Public Service Company
Pinnacle West Capital Corporation
Pinnacle West Energy Corporation

Docket Nos. EC00-118-000
and EC00-118-001

ORDER AUTHORIZING DISPOSITION OF JURISDICTIONAL FACILITIES

(Issued November 24, 2000)

I. Introduction

On July 28, 2000, as completed on August 23, 2000, Arizona Public Service Company (APS), Pinnacle West Capital Corporation (PWCC), and Pinnacle West Energy Corporation (PWE) (collectively, Applicants), filed a joint application pursuant to section 203 of the Federal Power Act (FPA)[1] requesting Commission authorization for APS to transfer to PWE certain jurisdictional facilities and operation agreements. In addition, APS requests authorization to transfer certain wholesale power sales agreements to PWCC. The jurisdictional facilities involved in the transaction include step-up transformers and other generation-related transmission facilities. The Commission has reviewed the proposed transactions under the Commission's Merger Policy Statement.[2] As discussed below, we will authorize the proposed transactions as consistent with the public interest.

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[1] 16 U.S.C. § 824b (1994).

[2] Inquiry Concerning the Commission's Merger Policy Under the Federal Power Act: Policy Statement, Order No. 592, 61 Fed. Reg. 68,595 (1996), FERC Statutes and Regulations, Regulations Preambles January 1991-June 1996 ¶ 31,044 (1996), reconsideration denied, Order No. 592-A, 62 Fed. Reg. 33,341 (1997), 79 FERC ¶ 61,321 (1997) (Merger Policy Statement).

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II. Background

A. Description of the Parties

PWCC is an Arizona corporation and an exempt public utility holding company under the Public Utility Holding Company Act of 1935 (PUHCA).[3] PWCC is the parent company of APS, PWE, and APS Energy Services Company, Inc. (APSES). PWCC has two non-utility subsidiaries, El Dorado Investment Company, an investment firm, and SunCor Development Company, a real estate developer. PWCC is also a power marketer authorized by the Commission to sell electric power at market-based rates.[4] PWE is a subsidiary of PWCC created to own and operate wholesale generating facilities.[5]

APS is an investor-owned utility engaged in generating, transmitting, and distributing electricity in Arizona. APS presently owns or partially owns several generating units that it proposes to transfer to Pinnacle West Energy. APS is also a power marketer authorized by the Commission to sell electric power at market-based rates.[6]

B. The Proposed Transaction

According to the application, the proposed transaction is part of the state restructuring proceedings and settlement agreement under which APS agreed to divest its generation assets by December 31, 2002, to an affiliate.[7] Applicants state the proposed

---

[3]15 U.S.C. 79c (1994).

[4]The Commission granted market-based authority to PWCC in Pinnacle West Capital Corporation, 91 FERC ¶ 61,290 (2000), reh'g pending.

[5]PWE is authorized to sell power at market-based rates. See Pinnacle West Energy Corporation, 92 FERC ¶ 61,248 (2000).

[6]The Commission granted market-based authority to APS in Arizona Public Service Company, 79 FERC ¶ 61,022 (1997).

[7]The Application states that the settlement approved by the Arizona Corporation Commission (Arizona Commission) on October 6, 1999, was intended to resolve retail electric competition related issues and approve unbundled tariffs.

transaction would allow APS to conduct business "primarily" as a wires company.[8] Applicants state that, starting in 2003, APS would be engaged only in providing regulated electric transmission and distribution services. The proposed transaction would enable PWE to conduct business as a generating company. It would sell most of the output from its generating facilities to PWCC, but it may also sell a portion of its output to other wholesale customers. As a result of this transaction, PWCC will have a marketing and trading department, will act as a power marketer, and will conduct trading and brokering functions on behalf of its subsidiaries (i.e., APS, PWE, and APSES). Pursuant to the restructuring plan, under separate agreements to be filed with the Commission, PWCC will provide APS with all of the generation-related ancillary services APS needs.[9]

Applicants claim that the proposed transaction is consistent with the public interest because it will not adversely affect competition, rates, or regulation and that it will benefit the public interest by: (1) finalizing the implementation of retail access in Arizona; (2) allowing competition in the generation markets; and (3) enabling APS to operate its transmission system as a "wires" only company.[10]

III. Notice and Interventions

Notice of the completed application was published in the Federal Register, with comments due on or before September 7, 2000.[11] The Arizona Corporation Commission (Arizona Commission) filed a notice of intervention. Timely motions to intervene were filed by Navajo Tribal Utility Authority (Navajo) and Salt River Agricultural Improvement and Power District (Salt River). In addition, a group of municipal water

[8]APS plans to be a "wires" only company once it completes its transfer of its nuclear generating units by the end of 2002. Until then, APS only claims that it is "primarily" a wires only company. See Application at 7-8.

[9]Applicants state that the rates for the ancillary services PWCC will provide to APS and APS's customers will be the same as the rates in APS's Open Access Transmission Tariff (Open Access Tariff) until a market for ancillary services develops in Arizona.

[10]Application at 8.

[11]65 Fed. Reg. 53,283 (2000).

districts in Arizona (Arizona Districts)[12] and Tohono O'odham Utility Authority (Tohono) filed timely motions to intervene accompanied by a protest.[13] Tucson Electric Power Company (Tucson) and Citizens Communications Company (Citizens) filed untimely motions to intervene.

On August 30, 2000, Applicants filed an answer in opposition to the protest of Tohono and Arizona Districts.

IV. Discussion

A. Procedural Matters

Pursuant to Rule 214 of the Commission's Rules of Practice and Procedure,[14] the Arizona Commission's notice of intervention and the timely, unopposed motions to intervene of Arizona Districts, Tohono, Navajo, and Salt River serve to make them parties to this proceeding. In addition, due to the absence of any undue prejudice or delay, we will grant the late, unopposed motions to intervene of Tucson and Citizens. While rule 213 (a)(2) of the Commission's Rules of Practice and Procedure[15] generally prohibits the filing of an answer to protests, we will accept Applicants' answer because it aids our understanding and resolution of the issues.

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[12]Arizona Districts consist of small utilities, political subdivisions, and special districts organized under Arizona law to provide electricity for irrigated agriculture and rural communities. Arizona Districts are comprised of: Aguila Irrigation District; Buckeye Water Conservation & Drainage District; Electrical District Nos. 1, 3, and 6 of Pinal County; Electrical District No. 7 and 8 of Maricopa County; Harquahala Valley Power District; Maricopa County Municipal Water Conservation District No. 1; McMullen Valley Water Conservation & Drainage District; Roosevelt Irrigation District; and Tonopah Irrigation District.

[13]Tohono is a subsidiary of the Tohono O'odham Nation, formerly known as the Papago Tribe of Arizona.

[14]18 C.F.R. § 385.214 (2000).

[15]18 C.F.R. §385.213 (a)(2) (2000).

B. Standard of Review Under Section 203

Section 203(a) of the FPA provides that the Commission must approve a proposed merger if it finds that the merger "will be consistent with the public interest." 16 U.S.C. § 824b(a) (1994). The Commission's Merger Policy Statement[16] provides that the Commission will generally take account of three factors in analyzing proposed mergers: (a) the effect on competition; (b) the effect on rates; and (c) the effect on regulation. In dispositions of jurisdictional facilities not involving a merger, the Commission applies these same factors in assessing whether to authorize such transactions.[17] Consistent with these factors, we find, for the reasons discussed below, that Applicants' proposed transactions are consistent with the public interest. Accordingly, we will approve the proposed disposition of jurisdictional facilities without further investigation.

C. Effect on Competition

Applicants state that the proposed transaction will not have an adverse effect on competition in the generation or transmission markets, and no intervenor disagrees. We agree with Applicants' general assertion that market structure will not be adversely affected by the proposed transaction. We note that the proposed transaction is a transfer of jurisdictional facilities internal to the APS/PWCC/PWE corporate family and will not result in a net loss of competitors from the generation market. Thus, we find that the proposed transaction will not adversely affect competition.

D. Effect on Rates

1. Arguments of the Parties

Applicants state that the proposed transaction will not adversely affect wholesale customers' rates. Applicants state that APS does not intend to alter its transmission rates because none of the transmission assets being acquired by PWE from APS are currently included in APS's transmission tariff rates. Applicants state that APS serves most of its

[16] See Merger Policy Statement, FERC Stats. & Regs. ¶ 31,044 at 30,117-18.

[17] See, e.g., Conectiv and NRG Energy, Inc., 92 FERC ¶ 61,031 at 61,069-70 (2000); Wisconsin Public Service Corporation and Upper Peninsula Power Company, 91 FERC ¶ 61,322 at 62,108 (2000)); Wisconsin Electric Power Company, 90 FERC ¶ 61,346 at 62,144 (2000); Wisconsin Power & Light Company, 90 FERC ¶ 61,347 at 62,148 (2000).

power customers under market-based rates or through transactions with the Western System Power Pool (WSPP). Applicants add that, while APS serves some wholesale customers under cost-based rates, all but two of those customers can choose alternative power suppliers. Applicants also state that they have proposed measures that will protect wholesale customers from any potential affiliate abuse that might arise from the transaction. Specifically, in the case of wholesale customers whose contracts include a pricing provision based on System Incremental Cost (SIC), Applicants propose to cap the pass-through of costs to such wholesale customers at the lesser of APS's SIC or prices calculated based on the Palo Verde Index. With regard to customers whose contracts contain a Fuel Adjustment Clause (FAC), Applicants propose that they pay the lesser of a FAC calculated with inter-affiliate transactions included, or a FAC calculated with the inter-affiliate transactions priced not as actual but at the Palo Verde Index price for a similar duration, or the average of the actual corrected FAC for the same month for 1998 or 1999.[18]

Applicants also propose protection for customers taking ancillary services. Applicants state that PWE will sell generation-related ancillary services to PWCC at the rates currently charged under APS's Open Access Tariff.[19] PWCC will, in turn, provide APS with its generation-related ancillary services at exactly the same charges. APS proposes to pass through, to customers subscribing to such ancillary services, the rates it pays PWCC for these services under its Open Access Tariff.[20]

Tohono argues that APS's SIC pricing provision will adversely impact its rates. Tohono argues that the Applicants have not shown how such a provision will effectively protect customers such as Tohono. Tohono maintains that the current SIC provision has been exceedingly volatile and is likely to become more volatile and unreasonable under Applicants' restructuring plan. Tohono states that this volatility occurs because the current costs are based on APS's generating units and that if the sales contracts and generating units are transferred to PWE, the SIC costs may be driven by inter-affiliate power purchases at negotiated rates.[21]

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[18]Application at 10.

[19]PWE and PWCC reserve the right to change such rates and services as their costs of providing such service change, or as conditions change.

[20]Application at 11.

[21]Tohono Protest at 3-5.

Arizona Districts contend that Applicants failed to provide adequate ratepayer protection to their customers for the sale of ancillary services. Thus, Arizona Districts request that the Commission approval of the transaction be conditioned on Applicants' customers receiving ancillary services at cost-based rates for five years under APS's existing Open Access Tariff. Secondly, Arizona Districts request the Commission defer action in this proceeding until it reviews the Applicants' agreements to sell ancillary services at cost-based rates under APS's existing Open Access Tariff. Arizona Districts express concern that, although Applicants commit that the acquisition of ancillary services will be at APS's existing Open Access Tariff rates until a market for ancillary services develops in Arizona, Applicants reserve the right to propose revisions to the rates and conditions of ancillary services as conditions warrant. Arizona Districts maintain that Applicants should provide assurances that they will provide ancillary services at APS's existing tariff rates.[22]

2. Applicants' Response

Applicants' answer to Tohono's and Arizona Districts' protests argues that the protests should be rejected because the proposal to charge APS the same rate as APS currently is charged under its Open Access Tariff has previously been accepted by the Commission.[23] In addition, Applicants argue that the Arizona Districts have not presented factual evidence that a five-year rate freeze is necessary.

3. Commission Determination

The Commission finds that the proposed transaction will not have an adverse effect on rates. We will accept Applicants' commitment to charge for ancillary services at the rates contained in APS's Open Access Tariff.[24] PWE will sell generation-related ancillary services to PWCC at rates identical to those APS itself pays under its Open Access Tariff. We note that Applicants' proposal does not raise any concerns because the ancillary services rates paid by PWCC are the same as those that other customers are required to pay.

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[22]Arizona Districts Protest at 4-6.

[23]See Allegheny Energy Supply Company, 89 FERC ¶ 61,258 (1999).

[24]However, we note that implementation of this proposal will require timely filing under section 205 of the FPA.

With respect to affiliate abuse, we deny Tohono's requests to set this issue for hearing.[25] Applicants have proposed measures that will protect wholesale customers from any potential affiliate abuse associated with the transaction. These measures include commitments offered by APS's affiliates, and accepted by the Commission, in previous cases.[26] Applicant reiterates here that it will continue to abide by these commitments. Applicants propose, in the case of wholesale customers whose contracts include a pricing provision based on SIC, to cap the pass-through of costs to such wholesale customers at the lesser of APS's SIC or prices calculated based on the Palo Verde Index.

Moreover, as to any adverse impact resulting from purchased power, we note that, at this juncture, these concerns are hypothetical. The customers may file complaints under section 206 of the FPA in the event these concerns materialize. Furthermore, Tohono concedes that, under their existing contract, APS is free to sell power to third parties and meet customers' needs through purchased power transactions and that customers would be charged for purchased power at the SIC. Thus, the proposed transfer of jurisdictional assets from APS would not change the status quo in this regard and would not adversely affect customers' rates.

E. Effect on Regulation

The Commission finds that the proposed transactions will not have an adverse effect on regulation. We reach this conclusion because the Commission will continue to have jurisdiction over the wholesale transactions of APS that are being transferred to PWCC and PWE. Moreover, APS will continue to be subject to the Commission's jurisdiction and the Arizona Commission for retail sales.

F. Consolidation of Dockets

Arizona Districts and Tohono request consolidation of this proceeding with that in Pinnacle West Energy Corporation, Docket No. ER00-3312-000. They argue that consolidation is appropriate because the proceedings involve the same entity and because all of these dockets raise common issues of fact and law.

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[25]Tohono Protest at 5.

[26]Pinnacle West Capital Corporation, 91 FERC ¶ 61,290 at 61,998 (2000), reh'g pending. See also Pinnacle West Energy Corporation, 92 FERC ¶ 61,248 at 61,790-91 (2000), reh'g pending.

We see no need to consolidate this proceeding with any other proceeding, since we are not setting it for hearing. Moreover, we note that, on September 26, 2000, the Commission issued an order accepting PWE's proposed market-based rate tariff.

The Commission orders:

(A) The motions to intervene of Arizona Districts, Tohono, Navajo, Salt River, Tucson, and Citizens are hereby granted, as discussed in the body of this order;

(B) Applicants' answer to the protests of Tohono and Arizona Districts is hereby granted, as discussed in the body of this order;

(C) The proposed disposition of jurisdictional facilities is hereby authorized, on the terms and conditions and for the purposes set forth in the application, as discussed in the body of this order;

(D) The foregoing authorization is without prejudice to the authority of the Commission or any other regulatory body with respect to rates, service, accounts, valuation, estimates or determinations of cost, or any other matter whatsoever now pending or which may come before the Commission;

(E) Nothing in this order shall be construed to imply acquiescence in any estimate or determination of cost or any valuation of property claimed or asserted;

(F) The Commission retains authority under sections 203(b) and 309 of the FPA to issue supplemental orders as appropriate; and

(G) Applicants shall promptly notify the Commission of the date the disposition of jurisdictional facilities is consummated.

By the Commission.

(S E A L)

Linwood A. Watson, Jr.,
Acting Secretary.

Exhibit F-1

Snell & Wilmer
L.L.P.
LAW OFFICES

One Arizona Center
Phoenix, Arizona 85004-0001
(602) 382-6000
Fax: (602) 382-6070

PHOENIX, ARIZONA
TUCSON, ARIZONA
IRVINE, CALIFORNIA
SALT LAKE CITY, UTAH

[PRELIMINARY]

November 20, 2000

Securities and Exchange Commission
450 Fifth Street, N.W.
Washington, D.C. 20549

Re: Pinnacle West Capital Corporation Form U-1 Application / Declaration
(File No. 070-09745)

Ladies and Gentlemen:

We are Arizona counsel for Pinnacle West Capital Corporation, an Arizona corporation (the "***Company***"), and are familiar with the matters relating to the "***Reorganization***," as such term is defined in the Form U-1 Application / Declaration (File No. 070-09745) under the Public Utility Holding Company Act of 1935, as amended (the "***Act***"), filed with the Securities and Exchange Commission (the "***Commission***") by the Company on September 12, 2000 (the "***Application***"). Capitalized terms used herein and not otherwise defined will have the meanings given in the Application. The term "***Assets***," when used herein will mean those assets actually contributed to Transitory Subsidiary in the Reorganization, as contemplated in the Application. The term "***Assumed Debt***," when used herein, will mean the indebtedness of APS actually assumed or agreed to be assumed by Transitory Subsidiary and ultimately by PWE in the Reorganization, as contemplated in the Application. Insofar as the fossil assets of APS may be acquired by PWE at different times, it is understood that the term "***Reorganization***," when used herein, will refer only to the first transaction described herein and in the Application whereby PWE acquires Assets of APS. We are aware that PWE may file an application with the Federal Energy Regulatory Commission for temporary status as an exempt wholesale generator pending Commission approval under the Act. As described in the Application, the Reorganization involves the following:

1. The formation of Transitory Subsidiary as a wholly-owned subsidiary of APS (the "***Formation***");

Member: LEX MUNDI, a global association of independent law firms with members in the United States and 60 countries throughout the world.

2. The contribution of the Assets and the Assumed Debt by APS to Transitory Subsidiary in exchange for the common stock of Transitory Subsidiary (the "*Capitalization*");

3. The distribution of the stock of Transitory Subsidiary by APS to the Company (the "*Spin-off*"); and

4. The merger of Transitory Subsidiary into PWE, with PWE surviving (the "*Merger*").

Among other things, we have examined:

(a) The Application;

(b) The parties' corporate proceedings and the proceedings before the Arizona Corporation Commission (the "*ACC*") relative to the Reorganization and related matters; and

(c) Such other documents and certificates (including those being delivered to you concurrently herewith) and such statutes, rules, and regulations as we have deemed relevant.

In our examination of the documents referred to above, we have assumed (i) the genuineness of the signatures not witnessed, the authenticity of documents submitted to us as originals, and the conformity to originals of documents submitted to us as copies; (ii) the legal capacity of all natural persons executing such documents; (iii) that such documents accurately describe and contain the mutual understanding of the parties, and that there are no oral or written statements or agreements that modify, amend, or vary, or purport to modify, amend, or vary, any of the terms of such documents; (iv) with respect to the Assumed Debt, that each such entity (other than APS, PWE, and Transitory Subsidiary), and with respect to all such other documents, that each such entity, had the power to enter into and perform its obligations under such documents, and that such documents have been duly authorized, executed, and delivered by, and are valid, binding upon, and enforceable against, such entities; (v) that the parties to such documents will receive no interest, charges, fees, or other benefits or compensation in the nature of interest in connection with the transactions other than those that the Company has agreed in writing in such documents to pay; and (vi) that no fraud has occurred in connection with such transactions.

Based upon the foregoing, and subject to the assumptions and conditions set forth herein, we are of the opinion that, in the event that the Reorganization is consummated in accordance with the Application:

1. All laws of the State of Arizona applicable to the Reorganization will have been complied with.

2. Following the Formation and the Capitalization, Transitory Subsidiary will be validly organized and duly existing.

3. The common stock of Transitory Subsidiary issued to APS in the Formation and the Capitalization will be validly issued, fully paid and non-assessable, and APS, as the holder of such stock following the Formation and the Capitalization, and the Company, as the holder of such stock immediately following the Spin-off, will be entitled to the rights and privileges appertaining thereto set forth in the articles of incorporation of Transitory Subsidiary.

4. PWE is validly organized and duly existing.

5. The common stock of PWE to be held by the Company following the Reorganization will be validly issued, fully paid and non-assessable, and the Company, as the holder of such stock immediately following the Merger, will be entitled to the rights and privileges appertaining thereto set forth in the articles of incorporation of PWE.

6. Following the Capitalization, the Assumed Debt that is assumed effective as of the date of the Capitalization will be the valid and binding obligation of Transitory Subsidiary in accordance with its terms. Upon the effective time of the Merger, the Assumed Debt that is assumed effective as of the date of the Merger be the valid and binding obligation of PWE in accordance with its terms.

7. Upon the effective time of the Spin-off, the Company will legally acquire the common stock of Transitory Subsidiary issued in the Capitalization.

8. The consummation of the Reorganization will not violate the legal rights of the holders of any securities issued by the Company or any "associate company," as defined in the Act, thereof.

The opinions expressed above are subject to the following assumptions and conditions:

(a) The Reorganization, as contemplated by the Application, will be authorized by the Commission. The Commission will duly enter an appropriate order or orders with respect to the Reorganization, as described in the Application, granting and permitting the Application to become effective under the Act and the rules and regulations thereunder and the Reorganization will be consummated in accordance with the Application.

(b) The Reorganization will be duly authorized and approved to the extent required by the governing documents and applicable federal and state laws, by the board of directors of each of APS, Transitory Subsidiary and PWE, and by the Company as the sole shareholder of APS, Transitory Subsidiary and PWE, and such authorizations and approvals remain in full force and effect.

(c) Without limitation of paragraph (b) above, the board of directors of Transitory Subsidiary will authorize the issuance of the common stock to APS in the Capitalization in accordance with Arizona law, and the number of shares so issued will be authorized in the articles of incorporation of Transitory Subsidiary.

(d) The Spin-off will be effected in accordance with Arizona law and the amount thereof will not exceed any limitation contained in APS' articles of incorporation.

(e) Instruments of merger will be duly and validly filed with the ACC, and such other corporate formalities as are required by the laws of the State of Arizona for the consummation of the Merger will be taken, and the Merger will become effective in accordance with the laws of the State of Arizona.

(f) None of the Capitalization, the Spin-off or the Merger will constitute a fraudulent conveyance and APS will not be rendered insolvent as a result of the Reorganization.

(g) All required approvals, authorizations, consents, certificates, and orders of, and all filings and registrations with, all applicable federal and state commissions and regulatory authorities with respect to the Reorganization will be obtained or made, as the case may be, and remain in effect (including the approval and authorization of the Commission under the Act, the Federal Energy Regulatory Commission under the Federal Power Act, as amended, and the rules and regulations thereunder, and the ACC under the applicable laws of the State of Arizona), and the Reorganization will be accomplished in accordance with all such approvals, authorizations, consent, certificates, orders, filings and registrations. APS will not utilize utility funds to form Transitory Subsidiary or to divest itself of Transitory Subsidiary.

(h) The parties will comply with, or obtain all consents, waivers and releases, if any, required for the Reorganization under all applicable governing corporate documents, contracts, agreements, debt instruments, indentures, franchises, licenses, and permits to be listed on a schedule to be provided by the Company and/or any of its associate companies.

(i) Our opinions herein are given solely with respect to the actual effectuation of the Reorganization, including with respect to consents, licenses, permits, filings with and approvals of governmental authorities that are required to effect the Reorganization, and no opinion is given as to whether APS, the Company, Transitory Subsidiary, or PWE or their businesses or operations are currently in compliance with any laws or will be after the Reorganization or as to any consents, licenses, permits, filings with or approvals of any governmental body or agency or other person required for the ownership or operation of the Assets before or following the Reorganization.

(j) The opinions set forth in paragraph 6 herein are subject to, and limited by, the following:

(i) the effect of any applicable bankruptcy, insolvency, reorganization, arrangement, moratorium or other similar laws relating to or affecting creditors rights generally;

(ii) the effect of general principles of equity, including (without limitation) concepts of materiality, reasonableness, good faith and fair dealing (regardless of whether considered in a proceeding in equity or at law);

(iii) the qualification that certain waivers, procedures, remedies, and other provisions of the documents governing the Assumed Debt may be unenforceable under or limited by the law of the State of Arizona; however, such law does not, in our opinion, substantially prevent the practical realization of the benefits intended by such documents; and

(iv) we express no opinion as to the effect of the law of any jurisdiction other than the State of Arizona wherein any creditor may be located or wherein enforcement of the Assumed Debt may be sought which limits the rates of interest legally chargeable or collectible.

(k) No act or event other than as described herein shall have occurred subsequent to the date hereof that would change the opinions expressed herein.

(l) The Reorganization will be consummated as described in the Application or with such changes as we have approved, and all legal matters incident thereto will be satisfactory to us. With respect to required approvals of the ACC, we note that two parties have filed legal actions challenging the validity of the Settlement as approved by the ACC. However, under Arizona law, an ACC order remains in effect pending appeal.

(m) In giving the final opinion required by the Commission in connection with the Reorganization, we may rely exclusively upon opinions of other counsel to the Company as to certain matters, or such other counsel may provide certain of such opinions in separate opinion letters provided to the Commission concurrently with our final opinion.

The opinions expressed herein are limited to the laws of the State of Arizona and, with respect to paragraphs 6 and 7, the federal law of the United States of America and we express no opinion on the laws of any other jurisdiction. Without limiting the foregoing, opinions herein relating to labor/employment or employee benefit matters, environmental matters, tax matters, and real estate matters are limited to the laws of the State of Arizona. The opinions expressed herein are based upon the law in effect on the date hereof, and we assume no obligation to revise or supplement this opinion should such law be changed by legislative action, judicial decision, or in any other manner, or otherwise to notify you of any changes in law or fact relevant to the opinions expressed herein. This opinion letter is rendered solely for your benefit in connection with the transactions described above, and this opinion letter is not to be used, circulated, quoted, or otherwise referred to for any other purpose.

We hereby consent to the use of this opinion as an exhibit to the Application.

Very truly yours,

Snell & Wilmer L.L.C.

Exhibit F-1

THE LAW FIRM OF
KELEHER
&McLEOD
A PROFESSIONAL ASSOCIATION

[PRELIMINARY]

November 21, 2000

Securities and Exchange Commission
450 Fifth Street, N.W.
Washington, D.C. 20549

Re: Pinnacle West Capital Corporation
Form U-1 Application/Declaration
(File No. 070-09745)

Ladies and Gentlemen:

We are special New Mexico counsel for Pinnacle West Capital Corporation, an Arizona corporation (the "**Company**"), in regard to certain matters relating to the "**Reorganization,**" as such term is defined in the Form U-1 Application/Declaration (File No. 070-09745) under the Public Utility Holding Company Act of 1935, as amended (the "**Act**"), filed with the Securities and Exchange Commission (the "**Commission**") by the Company on September 12, 2000 (the "**Application**"). Capitalized terms used herein and not otherwise defined will have the meanings given in the Application. The term "**Four Corners Transfer,**" when used herein, will mean the transfer of the Four Corners Power Plant from APS to PWE pursuant to the Reorganization, as contemplated in the Application, which we have examined.

APS has represented to us, and we have relied upon such representation, that the only business in which it is engaged in the State of New Mexico consists of and is limited to ownership and operation of electric generating units (or undivided interests therein) and electric transmission lines, sales of electricity at retail to BHP Navajo Coal Company ("**BHP**") solely for its conduct of coal mining operations on the Navajo Reservation ("**BHP Contract**"), transmission of electricity from Tucson Electric Power Company to the Navajo Tribal Utility Authority for resale, and wholesale transactions with other utilities.

APS and PWE have represented to us, and we have relied upon such representation, that the only asset located in the State of New Mexico that is being transferred from APS to PWE pursuant to the Reorganization is the Four Corners Power Plant.

Mailing Address
PO Drawer AA
Albuquerque NM 87103

Main Phone
505-346-4646

Street Address
Albuquerque Plaza
201 Third NW, 12th floor
Albuquerque NM 87102
Fax: 505-346-1370

414 Silver SW, 12th floor
Albuquerque NM 87102
Fax: 505-346-1345

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PWE has represented to us, and we have relied upon such representation, that it is not currently engaged in any business in the State of New Mexico, and that the only business in which it will be engaged in the State of New Mexico immediately following the Reorganization consists of and is limited to ownership and operation of electric generating units (or undivided interests therein) at the Four Corners Power Plant and the sale of power and energy at wholesale from the Plant.

The Company has represented to us, and we have relied upon such representation, that it is not engaged in any business in the State of New Mexico.

Our opinions herein are given solely with respect to the actual effectuation of the Four Corners Transfer, and no opinion is given as to whether APS, the Company, Transitory Subsidiary or PWE, or their businesses or operations, are currently in compliance with any laws, or will be after the Reorganization, or as to any consents, licenses, permits, filings with or approvals of any governmental body or agency or other person required for the ownership or operation of the Four Corners Power Plant before or following the Reorganization.

Our opinions relate only to the Four Corners Transfer. In respect only of the laws of New Mexico, and subject to the qualifications and limitations with respect to this opinion letter set forth above, we are of the opinion that:

1. The activities of APS in the State of New Mexico to date do not constitute it a "public utility" as that term is defined in the relevant laws of the State of New Mexico, and accordingly, no approval, authorization, or consent of the New Mexico Public Regulation Commission is required by APS for the Four Corners Transfer contemplated in the Application. In addition, the rates and charges pursuant to the BHP Contract between APS and BHP are not subject to regulation by the New Mexico Public Regulation Commission.

2. The activities of PWE in the State of New Mexico to date do not, and immediately following the Reorganization will not, constitute it a "public utility" as that term is defined in the relevant laws of the State of New Mexico, and accordingly, no approval, authorization, or consent of the New Mexico Public

Regulation Commission is required by PWE for the Four Corners Transfer contemplated in the Application.

The opinions expressed herein are limited to the laws of the State of New Mexico and we express no opinion about the laws of any other jurisdiction. The opinions expressed herein are based upon the law in effect on the date hereof, and we assume no obligation to revise or supplement this opinion should such law be changed by legislative action, judicial decision, or in any other manner, or otherwise to notify you of any changes in law or fact relevant to the opinions expressed herein. Without limitation of the foregoing, we express no opinion on the requirements that might become applicable upon the implementation of open access in New Mexico, currently scheduled to begin January 1, 2002. This opinion letter is rendered solely for your benefit in connection with the Four Corners Transfer described above, and this opinion letter is not to be used, circulated, quoted, or otherwise referred to for any other purpose.

We hereby consent to the use of this opinion as an exhibit to the Application.

Yours truly,

KELEHER & MCLEOD, P.A.

By: Susan McCormack
Susan M. McCormack

smm0090

UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
WASHINGTON, D.C. 20549

AMENDMENT NO. 2 TO
FORM U-1
APPLICATION
UNDER
THE PUBLIC UTILITY HOLDING COMPANY ACT OF 1935

PINNACLE WEST CAPITAL CORPORATION
400 East Van Buren Street, Suite 700
Phoenix, Arizona 85004

(Name of company filing this statement and address of principal executive offices)

None

(Name of top registered holding company parent)

Herbert I. Zinn
Pinnacle West Capital Corporation
400 North Fifth Street
Mail Station 8695
Phoenix, Arizona 85004

Mary Ann K. Huntington
Morgan, Lewis & Bockius LLP
1800 M Street, N.W.
Washington, D.C. 20036

(Name and address of agents for service)

The Commission is requested to send copies of all notices, orders, and communications in connection with this Application to:

Herbert I. Zinn
Pinnacle West Capital Corporation
400 North Fifth Street
Mail Station 8695
Phoenix, Arizona 85004

Mary Ann K. Huntington
Morgan, Lewis & Bockius LLP
1800 M Street, N.W.
Washington, D.C. 20036

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Pursuant to Sections 9(a)(2) and 10 of the Public Utility Holding Company Act of 1935 (the "Act"), Pinnacle West Capital Corporation, an Arizona corporation ("PNW"), hereby requests approval from the Securities and Exchange Commission (the "Commission") to establish a new public-utility company subsidiary in connection with the proposed corporate reorganization (the "Reorganization") involving the relocation of certain generation assets from Arizona Public Service Company ("APS"), PNW's existing public-utility company subsidiary, to Pinnacle West Energy Corporation ("PWE"), another wholly-owned subsidiary of PNW. As a result of this Reorganization, PWE will become an "electric utility company" and a "public-utility company" within the meaning of the Act, and, therefore, PNW will acquire an additional public-utility subsidiary. (However, PWE will not become a public service corporation under Arizona state law.) PNW will continue to meet the requirements for an intrastate exemption under Section 3(a)(1) of the Act and will continue to file annual exemption statements on Form U-3A-2 pursuant to Rule 2 of the Commission's regulations.

The purpose of the Reorganization is to comply with certain requirements set forth in rules adopted by the Arizona Corporation Commission ("ACC") that provide the framework for introduction of retail electric competition in Arizona (the "Competition Rules"), and in a final ACC order approving APS' settlement with various parties with respect to implementation of the Competition Rules (the "Settlement"). Pursuant to the Competition Rules and the Settlement, APS must separate its generating assets and competitive services from its transmission and distribution functions no later than December 31, 2002. PNW seeks Commission approval now, however, because APS intends to move a substantial portion of its generating assets to PWE during 2001. There may be some delays in moving particular assets from APS to PWE, pending

receipt by APS of certain consents or waivers from third parties with respect to such assets, but most of the non-nuclear generating assets are to be moved to PWE during 2001.

ITEM 1 DESCRIPTION OF PROPOSED TRANSACTION

A. Description of the Parties

1. Pinnacle West Capital Corporation: PNW was incorporated in 1985 under the laws of the State of Arizona. Through its subsidiaries, PNW is engaged in the generation, transmission, and distribution of electricity and the sale of energy services. Also through subsidiaries, PNW is involved in real estate development and in venture capital investment. On December 31, 1999, PNW employed approximately 7,534 people, including the employees of its subsidiaries. Of these employees, 6,234 were employees of its existing public-utility subsidiary, APS, and employees assigned to joint projects of APS where APS serves as a project manager. PNW's principal executive offices are located at 400 East Van Buren, Phoenix Arizona 85004. PNW is currently a public-utility holding company exempt from the provisions of the Act, except Section 9(a)(2), by reason of its filing of annual exemption statements on Form U-3A-2 pursuant to Rule 2 of the Commission's regulations. 17 C.F.R. § 250.2(a). PNW's direct, wholly-owned subsidiaries are described below and a copy of PNW's most recent Form U-3A-2 is attached as Exhibit G-1.

2. Arizona Public Service Company: APS is a public-utility company incorporated in 1920 under the laws of the State of Arizona. APS is a wholly-owned subsidiary of PNW. APS' principal executive offices are located at 400 North Fifth Street, Phoenix Arizona 85004. APS provides retail electric services principally in the State of Arizona and is actively engaged in the competitive wholesale electric markets. APS is subject to regulation by the ACC

with respect to retail rates, accounting, service standards, service territory, issuances of securities, siting, of generation and transmission projects and various other matters.

APS is also subject to the jurisdiction of the Federal Energy Regulatory Commission ("FERC") under Parts I, II, and III of the Federal Power Act for certain phases of its business, including regulation of its rates relating to wholesale sales of energy and interstate transmission, licensing its hydroelectric stations, accounting, and certain other matters. APS' current business structure consists of three primary business units: generation; power marketing; and transmission/distribution. The following briefly describes these business units.

a. ***Generation*** -- APS currently owns or leases generating facilities with a total accredited capacity of approximately 4,000 megawatts. The fuel mix of APS' generation capacity is 41.8% coal; 31.5% gas or oil; 26.5% nuclear; and less than 1% other. APS' sources of energy during 1999 were approximately 56.8% from its own generation resources and approximately 43.2% from purchased power. The Reorganization involves the relocation of a substantial portion of APS' generating facilities and related facilities, as well as the transfer of certain of the employees of APS' generation business unit. The generating assets being moved to PWE during 2001 are briefly described below.[1] Also, attached, as Exhibit E-1, is a map showing the location of each of APS' generation facilities.

---

[1] In addition to the generating facilities to be moved during 2001, APS also owns or leases an interest in the Palo Verde Nuclear Generating Station ("PVNGS"), a three-unit nuclear generating facility located in Wintersburg, Arizona approximately 55 miles west of Phoenix, Arizona. The total accredited capacity of PVNGS is 3,733 megawatts, of which APS owns or leases 29.1%, or approximately 1,086 megawatts. APS is also the operator of the facility. There are six other co-owners of PVNGS, which collectively own or lease the remaining 70.9%. Ownership is in the form of a co-tenancy, and the co-owners are not affiliates of one another. APS operates PVNGS pursuant to an agreement in which each owner pays its proportionate share of the cost of operating the facility. While the Reorganization involving APS' non-nuclear generating facilities is contemplated to occur during 2001, APS does not plan to move its interest in PVNGS to PWE until 2002. The delay in moving the nuclear assets is to ensure additional time to adequately address complicated contractual arrangements, such as sale and leaseback provisions between APS and certain owner trusts to which APS has sold and leased back a portion of its interest in

Four Corners Power Plant ("Four Corners"):

Four Corners is a five-unit coal fired power plant located near Farmington, New Mexico on the Navajo Reservation. The property underlying the plant is held under easements granted by the federal government and under leases from the Navajo Nation. Units 1, 2 and 3 have an accredited capacity of 560 megawatts. These units are 100% owned and operated by APS. Units 4 and 5 have an accredited capacity of 1,480 megawatts; APS owns 15% of units 4 and 5, or 222 megawatts. The remaining interests in units 4 and 5 are co-owned by five other entities. Ownership of units 4 and 5 is through a co-tenancy arrangement, and the co-owners are not affiliates of one another. APS operates Four Corners units 4 and 5 pursuant to an agreement in which each owner pays its proportionate share of the operating cost.

Cholla Power Plant ("Cholla"):

Cholla is a four-unit coal-fired power plant located in Navajo County approximately 200 miles northeast of Phoenix, Arizona. Units 1, 2 and 3 have an accredited capacity of 615 megawatts. These units are 100% owned and operated by APS. Unit 4 has an accredited capacity of 380 megawatts; unit 4 is 100% owned by another unaffiliated entity. APS is also the operator for this unit.

Navajo Power Plant ("Navajo"):

Navajo is a three-unit coal-fired plant located south of Page, Arizona. The total accredited capacity for the plant is 2,250 megawatts. APS owns 14%, or 315 megawatts of this plant. The remaining interests in the plant are co-owned by five other entities which are not affiliated with APS. APS does not operate Navajo.

PVNGS Unit 2 and the PVNGS common facilities. There are also certain financial and economic considerations that must be resolved before the nuclear assets can be moved to PWE.

Saguaro Power Plant ("Saguaro"):

Saguaro is a four-unit power plant consisting of two gas/oil-fired steam units and two gas/oil-fired combustion turbine units and is located 30 miles north of Tucson, Arizona. The total accredited capacity for the plant is 319 megawatts. Steam units 1 and 2 have a combined capacity of 209 megawatts, and the two combustion turbines have a combined capacity of 110 megawatts. This plant is 100% owned and operated by APS.

Ocotillo Power Plant ("Ocotillo"):

Ocotillo is a six-unit multi-fueled generating plant located in Tempe, Arizona. Two units are gas/oil-fired steam units; two units are gas/oil-fired combustion turbines; and two units are solar. The total accredited capacity for steam units 1 and 2 is 226 megawatts; for combustion turbine units 1 and 2, the accredited capacity is 110 megawatts; and for solar units 1 and 2, the accredited capacity is 172 kilowatts. This plant is 100% owned and operated by APS.

Yucca Power Plant ("Yucca"):

Yucca is a five-unit gas/oil combustion turbine plant located near Yuma, Arizona. The accredited capacity of units 1, 2, 3 and 4 is 147 megawatts. These units are 100% owned and operated by APS. Unit 5 and a separate steam unit are owned by a separate, unaffiliated entity but operated by APS.

West Phoenix Power Plant ("West Phoenix"):

West Phoenix is a six-unit gas/oil-fired steam, combustion turbine, and combined cycle generation plant located in Phoenix, Arizona. Combustion turbine units 1 and 2 have an accredited capacity of 110 megawatts; combined cycle units 1, 2 and 3 have an accredited capacity of 255 megawatts; and steam units 4, 5 and 6 have an accredited capacity of 108.3 megawatts. APS owns or leases and operates 100% of West Phoenix and is entitled to 100% of the output.

Douglas/Fairview Power Plant:

Douglas/Fairview is a single combustion turbine unit with a capacity rating of 16 megawatts located near Douglas, Arizona. Douglas/Fairview is 100% owned and operated by APS.

Solar Power Plants

APS also owns a number of solar units that will be moved to PWE as part of the Reorganization. These solar units are located around the state (primarily in the Phoenix metropolitan area) and have a total combined capacity rating of 1 megawatt.

b. ***Power Marketing*** -- APS' Power Marketing and Trading division ("Power Marketing") primarily engages in the sale and purchase of electric capacity and energy in the wholesale market. Power Marketing sells excess power from APS' generation facilities and also purchases energy from other entities to meet APS' requirements to supply retail and wholesale customers. Power Marketing also engages in hedging transactions in forward markets for electricity and fuel and in the purchase and sale of emission allowances as part of APS' effort to manage risks associated with its generation and distribution activities. The ACC Competition

Rules and Settlement contemplate that as a competitive asset, APS would also move its Power Marketing division to an affiliate. Accordingly, on October 1, 2000, Power Marketing became a division of PNW.[2]

c. ***Transmission/Distribution*** -- APS owns and operates approximately 5,296 miles of transmission lines, of which all but 140 miles are located within the State of Arizona. APS' transmission was built primarily to bring generation from its power plants to its retail electric loads in Arizona. Ownership and operation of APS' transmission facilities is subject to regulation by FERC. Transmission rates are prescribed by FERC and the use of and access to the transmission system is subject to FERC's open access requirements set forth in FERC Order No. 888. As of December 31, 1999, APS' distribution system served approximately 827,000 electric retail customers in its service territory within the State of Arizona. APS provides distribution services in 11 of Arizona's 15 counties, including the metropolitan Phoenix area. Pursuant to the Settlement approved by the ACC in 1999, which is more fully discussed below, retail rates have been set until July 1, 2004, subject to conditions or circumstances which constitute an emergency. APS' transmission and distribution business will remain with APS under the Reorganization.

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[2] PNW itself did not become an electric utility company when this occurred. The Commission and Staff have both recognized, on numerous occasions, that marketing activities are not utility activities under the Act. See, e.g., UNITIL, Holding Company Act Release No. 26650 (Jan. 21, 1997); SEI Holdings, Inc., Holding Company Act Release No. 26581 (Sept. 26, 1996); Sunoco Power Marketing, L.L.C., SEC No-Action Letter, 1997 SEC No-Act. LEXIS 785 (July 24, 1997); Enron Capital & Trade Resources Corp., SEC No-Action Letter, 1997 SEC No-Act. LEXIS 287 (Feb. 13, 1997); Eastex Power Marketing, Inc., SEC No-Action Letter, 1996 SEC No-Act. LEXIS 536 (Apr. 30, 1996); LG&E Power Marketing, Inc., SEC No-Action Letter, 1996 SEC No-Act. LEXIS 510 (Apr. 26, 1996); Coral Power, L.L.C., SEC No-Action Letter, 1996 SEC No-Act. LEXIS 314 (Feb. 22, 1996); AIG Trading Corp., SEC No-Action Letter, 1995 SEC No-Act. LEXIS 195 (Jan. 20, 1995); Inter-Coast Power Marketing Co., SEC No-Action Letter, 1994 SEC No-Act. LEXIS 886 (Dec. 6, 1994); Electric Clearinghouse, Inc., SEC No-Action Letter, 1994; SEC No-Act. LEXIS 452 (Apr. 13, 1994); CRSS Power Marketing, Inc., SEC No-Action Letter, 1994 SEC No-Act. LEXIS 431 (Mar. 31, 1994).

3. **Pinnacle West Energy Corporation:** PWE was incorporated in Arizona on September 27, 1999 under the laws of the State of Arizona. PWE is a wholly-owned subsidiary of PNW. PWE was organized primarily to engage in the business of developing, owning, and operating generation plants used for the production and sale of wholesale energy. Currently, PWE is engaged in the development of approximately 2,600 megawatts of generating capacity in the State of Arizona and operations in other states are contemplated, too; however, PWE is not currently an electric utility company or a public-utility company within the meaning of the Act. Upon consummation of the Reorganization described herein and the subsequent relocation of APS' nuclear generating facilities, PWE will own or lease the generation facilities currently owned or leased by APS and will assume APS' responsibilities as operator of the facilities described above, with the exception of the Navajo Generating Station, which will continue to be operated by another, unaffiliated entity.[3] PWE's principal place of business is 400 North Fifth Street, Phoenix, Arizona 85004.

4. **APS Energy Services Company, Inc. ("APSES"):** APSES is an Arizona corporation formed in 1998. APSES is a wholly-owned subsidiary of PNW. APSES was organized as a retail power marketer to provide retail energy and related retail energy services to customers throughout Arizona, California, and other states that have instituted retail direct access. APSES does not own or control electric power generation, transmission, or distribution facilities.[4] APSES' principal place of business is 400 East Van Buren Street, Phoenix, Arizona.

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[3] In the future, PWE may also acquire or develop other generating assets. To the extent necessary for PNW to maintain its intrastate exemption, PWE may establish exempt wholesale generator ("EWG") subsidiaries to own and/or operate future assets that may be located out of state.

[4] APSES is not an "electric utility company" or a "public-utility company" as those terms are defined in the Act. See, e.g., Enron, SEC No-Action Letter (1997).

5. **SunCor Development Company ("SunCor"):** SunCor was incorporated in 1965 under the laws of the State of Arizona. SunCor is a wholly-owned subsidiary of PNW. SunCor is engaged in commercial and residential real estate development. SunCor is not engaged in generating, transmitting, distributing or selling electric energy and will not be affected by the Reorganization. SunCor's principal place of business is 3838 North Central, Suite 1500, Phoenix, Arizona 85012.

6. **El Dorado Investment Company ("El Dorado"):** El Dorado was incorporated in 1983 under the laws of the State of Arizona. El Dorado is an investment company and wholly-owned subsidiary of PNW. El Dorado is not engaged in the business of generating, transmitting, distributing, or selling electric energy and will not be affected by the Reorganization. El Dorado's principal place of business is 400 East Van Buren Street, Suite 800, Phoenix, Arizona 85004.

B. Regulatory Background

The Reorganization is being undertaken in accordance with the Competition Rules and Settlement. Specifically, in Arizona, the ACC has adopted the Competition Rules to expedite the transition to retail electric competition. Among other things, the Competition Rules required that APS separate its generation assets and competitive business activities from its transmission and distribution functions. In 1999, the ACC approved the Settlement between APS and several customer groups and consumer advocates resolving retail electric competition-related issues and approving unbundled tariffs.[5] Under the terms of the Competition Rules and the Settlement, retail choice for APS' retail customers is being phased-in. All of APS' retail customers will be

[5] The ACC order approving the Settlement is attached as Exhibit D-4.

entitled to choose their retail power supplier beginning January 1, 2001.[6] The retail rates of customers that continue to take fully bundled service from APS and do not choose an alternative supplier will be subject to planned rate reductions that will continue until July, 2004.[7] Under the Settlement, APS is entitled to apply for a change in the agreed upon rate reductions only in the event of an emergency or a material change in its cost of service as a result of specified extraordinary events. The Settlement also requires APS to complete separation of its generation assets by December 31, 2002.[8]

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6 See Exhibit D-4.
7 See Exhibit D-4.
8 See Exhibit D-4.

C. The Reorganization

PNW and APS propose to undertake the Reorganization pursuant to the arrangements described in the Term Sheet,[9] attached as Exhibit B-1 hereto.

The principal transactions associated with the Reorganization are described below. As previously mentioned, APS and PWE are both currently direct, wholly-owned subsidiaries of PNW. APS and PWE will be the only two "public-utility company" (as defined in the Act) subsidiaries of PNW upon the completion of the Reorganization. It is contemplated that the following transactions will occur during 2001: First, APS will contribute the bulk of its fossil and solar generating facilities, assets and related operational agreements to one or more of these newly-formed subsidiaries (hereafter "Transitory Subsidiaries") which will be wholly-owned by APS. This transaction is intended to qualify as a tax-deferred reorganization under Internal Revenue Code ("IRC") Section 368(a)(1)(D). Second, APS will distribute or cause to be distributed all of the stock of each Transitory Subsidiary to PNW in a transaction intended to qualify as a tax-deferred spin-off under IRC Section 355. Third, under state law, the Transitory Subsidiaries will then be merged into PWE (with PWE as the surviving entity) in a transaction intended to qualify as a tax-deferred statutory merger under IRC Section 368(a)(1)(A). It is contemplated that the three aforementioned transactions will occur simultaneously.

When the Reorganization is complete and APS' nuclear generating assets have been moved to PWE, APS' existing divisional structure in which its electric utility operations are divided along functional lines will be formalized, and separate corporate entities will engage in the transmission/distribution of electricity and the generation of electricity. APS will become a

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[9] Although the term sheet indicates that the Reorganization will take place "on or before January 1, 2001," the Reorganization is now contemplated to occur during 2001.

"wires" company and continue to own and operate its existing electric transmission/distribution system, and PWE will become a "generating" company and will own or lease and operate APS' existing generation assets and sell the output from these assets at wholesale to Power Marketing. Power Marketing, in turn, is expected then to sell power to APS and other non-affiliated power purchasers. APS will continue to provide transmission and distribution services at regulated rates, as well as provide energy to those retail customers in APS' existing service territory that do not elect to use an alternate retail power supplier. A diagram of PNW's corporate structure, after the Reorganization is complete and the nuclear generating facilities have been moved to PWE, is shown on Appendix B to Exhibit D-1 attached hereto.

Consummation of the Reorganization is subject to certain conditions as stated in the Term Sheet attached as Exhibit B-1. Principally, these conditions include: (a) the approval of the Commission under Section 9(a)(2) of the Act; (b) approvals of FERC under Sections 203 and 205 of the Federal Power Act 16 U.S.C. §§824b and d (1994); and (c) consents and waivers of certain third parties with respect to contracts associated with the generation assets. The approval of the ACC has already been granted. [10] No PNW shareholder approval is required in connection with the Reorganization. Although APS does not believe that shareholder approval is required for the Reorganization, the approval of its sole shareholder is being obtained.[11] The approval of APS' Board of Directors was obtained prior to the end of 2000.

---

[10] Approval from the Nuclear Regulatory Commission ("NRC") will be obtained in connection with the movement of APS' interest in its nuclear generating assets, which will occur by year-end 2002. No NRC approval, however, is necessary in connection with the Reorganization involving APS' non-nuclear generating facilities. Approval of some plant participants may also be required.

[11] As a wholly-owned subsidiary of PNW, APS' only shareholder is PNW.

D. Purpose and Anticipated Effects of the Reorganization

The principal purpose of the Reorganization and the subsequent relocation of APS' nuclear generating facilities to PWE is to assure compliance with the provisions of the Competition Rules and the Settlement and provide PNW with increased financial, managerial, and organizational flexibility which will enable APS and PWE to effectively compete in a restructured utility industry. After extensive investigation and analysis, PNW has determined that the proposed Reorganization offers the best means of positioning the PNW system for future changes and opportunities and will enable PNW to take advantage of emerging business opportunities and manage risks to the benefit of both shareholders and customers. The Reorganization is the first step in a clear functional and corporate separation between PNW's competitive generation business, and its distribution and transmission business, enabling each company to focus its resources on more clearly defined product markets and services. The intent of the Reorganization and subsequent relocation of APS' nuclear generating facilities is to create a financially sound and responsive utility system which can provide utility services effectively and efficiently. Additionally, the corporate division along functional lines will provide a better structure for regulators to assure that there is no cross-subsidization of costs or transfer of business risk from the competitive generation business to the fully-regulated transmission/distribution business. Moreover, this type of corporate division of utility operations along functional lines is becoming a highly-desirable form of conducting both a regulated transmission/distribution business and a competitive generation business.

The Reorganization will have no adverse effect on APS' existing electric utility operations. The Reorganization will not cause substantive changes in PNW's ultimate interest in existing utility businesses and will not involve the transfer or acquisition of any additional utility

assets beyond those currently held by APS or those which may be developed or acquired by PWE in the future. The managers and employees in PNW's existing utility operations will continue to perform their existing functions -- either as employees of APS, the transmission/distribution company, or as employees of PWE, the generating company. Thus, even though day-to-day utility operations would not be affected, the benefits discussed above will accrue to PNW and its customers and shareholders as a result of the Reorganization and the subsequent relocation of APS' nuclear generating facilities to PWE.

E. Additional Information

No associate company or affiliate of PNW or APS, or any affiliate of any associate company of PNW or APS, has any direct or indirect material interest in the proposed Reorganization except as stated herein.

ITEM 2 FEES, COMMISSIONS AND EXPENSES

The fees, commission and expenses to be paid or incurred by PNW and APS in connection with the Reorganization are estimated as follows:

Auditors' Fee	*
Legal Fees	*
Miscellaneous	*
Total	*

* To be filed by amendment

ITEM 3 APPLICABLE STATUTORY PROVISIONS

Sections 9(a)(2) and 10 of the Act are applicable to the proposed Reorganization. As a result of the proposed Reorganization, PNW will have two wholly-owned, public-utility company subsidiaries, APS and PWE. Section 9(a)(2) of the Act requires Commission approval before a person may acquire more than 5% of the outstanding voting securities of more than one "public-utility company." The standards for approval of a transaction under Section 9(a)(2) of the Act are set forth in Section 10 of the Act. The relevant standards under Section 10 are set forth in Section 10(b), 10(c) and 10(f).

For the reasons explained below, the Commission should approve the Reorganization pursuant to Section 9(a)(2) of the Act because it complies with the applicable standards of Section 10. PNW respectfully requests that the Commission issue an order approving the Reorganization by March 1, 2001, so that PNW has sufficient time to complete the Reorganization during 2001.[12] PNW anticipates moving most of the assets and personnel during 2001,[13] and believes that the time between the requested approval date of March 1, 2001, and the contemplated Reorganization is necessary to allow the transfer of personnel and to implement other aspects of the Reorganization.

A. Approval of the Reorganization under Section 9(a)(2).

Section 9(a)(2) makes it unlawful, without approval of the Commission under Section 10, "for any person . . . to acquire, directly or indirectly, any security of any public-utility company, if such person is an affiliate . . . of such company and of any other public utility or holding

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[12] In the event the Commission does not issue its order prior to the anticipated date of Reorganization, PWE intends to file an application with FERC for EWG status and limit its activities exclusively to the ownership and

company, or will by virtue of such acquisition become such an affiliate." By virtue of the proposed Reorganization, PNW will own more than 5% of the outstanding voting securities of two "public-utility companies" (APS and PWE) thus becoming an affiliate of both of these public-utility companies. Under Section 2(a)(5) of the Act, a "public-utility company" is an "electric utility company" or a "gas utility company." Under Section 2(a)(3) of the Act, an "electric utility company" is defined as "any company which owns or operates facilities used for the generation, transmission, or distribution of electric energy for sale . . . ." Upon completion of the Reorganization, PWE will own and operate certain of APS' existing facilities for the generation of electric energy for sale, and APS will continue to own and operate its existing facilities for the transmission and distribution of electric energy for sale, as well as its nuclear generating facilities. Therefore, both PWE and APS will be public-utility companies within the meaning of the Act.

1. Section 10(b)

Section 10(b) provides that the Commission shall approve an acquisition pursuant to Section 9(a)(2) unless the Commission finds that:

(1) such acquisition will tend towards interlocking relations or the concentration of control of public-utility companies, of a kind or to an extent detrimental to the public interest or the interest of investors, or consumers;

(2) in case of the acquisition of securities or utility assets, the consideration, including all fees, commissions, and other remuneration, to whomsoever paid, to be given, directly or indirectly, in connection with such acquisition is not reasonable or does not bear a fair relation to the sums invested in or the earning capacity of the utility assets to be acquired or the utility assets underlying the securities to be acquired; or

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operation of eligible facilities and sale of power at wholesale in order to maintain EWG status until the Commission issues an order approving the Reorganization.

[13] As noted above, certain generating assets, such as PVNGS, may be moved to PWE at a later date.

(3) such acquisition will unduly complicate the capital structure of the holding-company system of the applicant or will be detrimental to the public interest or the interest of investors or consumers or the proper functioning of such holding-company system.

PNW respectfully submits that no adverse findings should be made under any of these provisions.

a. "Detrimental Interlocking Relations" or "Concentration of Control" -- Section 10(b)(1)

Consistent with Section 10(b)(1) of the Act, PNW submits that the Reorganization will not tend towards interlocking relations or the concentration of control of public-utility companies, of a kind or to an extent detrimental to the public interest or the interest of investors or customers. The Reorganization involves the first step in the ultimate segregation of APS' existing utility assets and operations along functional lines into a generation company (PWE) and a transmission and distribution company (APS).

While there may be certain common directors and officers of PNW and the public-utility subsidiaries, these relations normally exist in public-utility holding company systems among affiliated and associated companies and should not be considered detrimental to the public interest or the interest of investors or consumers. See Central Maine Power Company, et al., Holding Co. Act Release No. 26903 (Aug. 7, 1998); CIPSCO, Inc., Holding Co. Act Release No. 25152, 47 SEC Docket 174 (Sept. 18, 1990).

Similarly, the Reorganization should not, within the meaning of Section 10(b)(1), be deemed to tend towards any "concentration of control of public-utility companies" that might be detrimental to the public interest, consumers or investors. The Reorganization will not involve the acquisition or control of any utility assets or operations which are not already owned or controlled by PNW or its existing public-utility subsidiary, APS, or being developed by PWE,

and "will therefore have no effect on the concentration of control of public-utility companies." Central Maine Power Company, et al., Holding Co. Act Release No. 26903 (Aug. 7, 1998); accord BEC Energy, et al., Holding Co. Act Release No. 26874 (May 15, 1998); Energy East Corp., Holding Co. Act Release No. 26834 (March 4, 1998); Wisconsin Energy Corp., Holding Co. Act Release No. 24267 (Dec. 18, 1996).

b. Fairness of Consideration and Fees -- Section 10(b)(2)

Section 10(b)(2) of the Act requires the Commission to determine whether the consideration paid in connection with a proposed acquisition of securities is reasonable and bears a fair relation to the investment in and earning capacity of the utility assets underlying the securities being acquired.

The generating assets will be recorded on the books of PWE at net book value. In addition, PWE will assume certain outstanding debt associated with the generating assets being moved. The valuation of PNW's investment in the securities of PWE and APS will be adjusted accordingly to reflect the movement of these assets and the associated debt to PWE. [14]

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[14] Specifically, PWE will assume APS' rights and obligations with respect to approximately $180 million in pollution control bonds issued by Navajo County, Arizona, Pollution Control Corporation and Coconino County, Arizona, Pollution Control Corporation. These two series of bonds were issued by the respective pollution control corporations under two separate Indentures of Trust dated as of August 1, 1993 between the issuer and an independent trustee. In each case, the issuer loaned the proceeds of the bonds to APS under a Loan Agreement dated as of August 1, 1993, and APS is responsible to repay the loan by making payments on the bonds when due. APS' obligations are secured by First Mortgage Bonds issued by APS and delivered to the Trustee for the pollution control bonds. At the time generating assets are moved to PWE, APS will assign its rights and obligations under the Loan Agreements to PWE, and PWE will assume such obligations. APS will remain primarily liable for such obligations and the First Mortgage Bonds will remain outstanding.

PWE will also assume APS' obligations under another approximately $60 million of pollution control bond debt, releasing APS from such obligations. No bondholder consent is required in connection with PWE's assumption of this debt. However, APS must give advance notice to the bondholders and any bondholder who does not wish to continue to hold the bonds may tender its bonds for purchase. In addition, if the issuance of a new letter of credit in substitution for the existing letter of credit supporting the bonds causes the ratings on the bonds to be lower than the existing rating, the bonds will be subject to a mandatory tender on the substitution date, and all the bonds will be subject to mandatory repurchase and remarketing on that date.

Since the Reorganization involves an entirely intra-company movement of existing assets from one wholly-owned subsidiary to another and not the acquisition of new assets or securities, PNW believes that the valuation established for purposes of this asset transition is reasonable and bears a fair relationship to the sums invested in the assets. PNW, as the sole owner of both APS and PWE, can expect to earn a fair return on its investment in APS and its investment in PWE.

An estimate of the fees and expenses to be paid in connection with the Reorganization is stated in Item 2 above. Such fees and expenses will be reasonable and customary for a transaction of this kind and will not be material when measured against PNW's consolidated book value or the earning capacity of its assets. See, e.g., Energy East Corp., Holding Co. Act Release No. 27128 (Feb. 2, 2000).

c. Complication of Capital Structure -- Section 10(b)(3)

Section 10(b)(3) of the Act requires the Commission to determine whether the transaction will unduly complicate the capital structure of the PNW system, be detrimental to the public interest, the interest of the investors or consumers, or the proper functioning of the holding-company system. No such effect will result from the Reorganization.

The Reorganization will not involve the creation of any ownership interests other than those necessary to maintain the basic corporate relationships of the reorganized holding-company system. Pursuant to the Reorganization, PNW will continue to be the only issuer of publicly owned equity securities in the system. PNW will continue to own all of the outstanding common stock of PWE, APS, and PNW's existing non-utility subsidiaries; there will be no minority equity interest in any of PNW's public-utility subsidiaries. As noted above, certain pollution control bonds issued by APS will be assumed by PWE, but this will in no way complicate the capital structure of PNW, APS, or PWE. This type of capital structure is typical of a contemporary holding company system and is within the traditional standards of the Act.

Moreover, the Reorganization is a significant step toward the ultimate goal of creating separate entities to perform PNW's transmission/distribution business and its generation business in compliance with the ACC's Competition Rules and the Settlement. Consequently, because the Reorganization does not complicate the capital structure of PNW, APS, or PWE, the standards of Section 10(b)(3) of the Act are satisfied.

2. Section 10(c)

The relevant provisions of Section 10(c) of the Act state that the Commission shall not approve:

(1) an acquisition of securities or utility assets, or of any other interest, which is unlawful under the provisions of Section 8 or is detrimental to the carrying out of the provisions of Section 11; or

(2) the acquisition of securities or utility assets of a public-utility or holding company unless the Commission finds that such acquisition will serve the public interest by tending towards the economical and the efficient development of an integrated public-utility system . . . .

APS and PNW respectfully submit that no adverse determination should be made under either of these provisions.

a. Significant Benefits -- Section 10(c)(1)

Section 10(c)(1) prohibits an acquisition of securities which is "unlawful under the provisions of Section 8" or "detrimental to the carrying out of the provisions of Section 11." By their express terms, Sections 8 and 11 apply only to registered holding companies and do not apply to exempt holding companies. After the Reorganization, PNW will continue to be exempt from all provisions of the Act, except Section 9(a)(2), pursuant to Section 3(a)(1) of the Act since PNW and its utility subsidiaries, APS and PWE, will each be predominantly intrastate in character, carry on their businesses substantially in Arizona, and be organized in Arizona. Accordingly, Section 8 of the Act is inapplicable to the Reorganization.

For the purposes of the Commission's review of the proposed reorganization of a holding company, the relevant provision of Section 11 is Section 11(b)(2), which requires the Commission to find that "the corporate structure . . . of any company in the holding-company system does not unduly or unnecessarily complicate the structure . . . of such holding-company system." In that connection, the Commission has construed this requirement, "to mean that the structural change must result in significant benefits to the holding-company system." CIPSCO Inc., Holding Co. Act Release No. 25152, 47 SEC Docket at 178 (Sept. 18, 1990); accord Central Maine Power Company, et al., Holding Co. Act Release No. 26903 (Aug. 7, 1998); BEC Energy, et al., Holding Co. Act Release No. 26874 (May 15, 1998); Energy East Corp., Holding Co. Act Release No. 26834 (March 4, 1998).

As discussed above in Section D of Item 1, the corporate structure resulting from the Reorganization will yield significant benefits. Most importantly, the Reorganization and subsequent move of APS' nuclear generating facilities to PWE will enable APS to implement the requirements of ACC Competition Rules and Settlement. In addition, segregation of the separate

utility functions into separate corporations dedicated solely to those functions will: (1) enable the executives, officers, and managers of APS and PWE to concentrate on the delivery of cost efficient and effective utility services responsive to the needs of customers; (2) allow PNW's subsidiaries and affiliates to be more competitive in their businesses; (3) segregate the financial and legal risks associated with those businesses; (4) ensure that there is no cross-subsidization of costs or business risk; and (5) aid the investment community in analyzing and valuing individual lines of business. In cases involving corporate reorganizations or the formation of holding companies, the Commission has held that the existence of these kinds of potential benefits satisfies the statutory standard of Section 10(c)(1). See, e.g., Central Maine Power Company, Holding Co. Act Release No. 26903 (Aug. 7, 1998); Atlanta Gas Light Company, Holding Co. Act Release No. 26482, 61 SEC Docket 1057 (March 5, 1996); SIGCORP, Inc., Holding Co. Act Release No. 26431, 60 SEC Docket 90 (Dec. 14, 1995); PP&L Resources, Inc., Holding Co. Act Release No. 26248, 58 SEC Docket 2634 (March 10, 1995); CIPSCO Inc., Holding Co. Act Release No. 25152, 47 SEC Docket 174 (Sept. 18, 1990); Wisconsin Energy Corp., Holding Co. Act Release No. 24267 (Dec. 18, 1996).

b. Economics and Efficiencies of an Integrated System – Section 10(c)(2)

Under Section 10(c)(2), the Commission must find that the Reorganization tends towards the economical and efficient development of an integrated public utility system. PNW respectfully submits that this standard is met in this case.

(i) Economics and Efficiencies

A number of economies and efficiencies will result from the PNW structure. Some of these benefits are described in Section D of Item 1 and Section A.2.a of Item 3, above. Overall, the Reorganization will permit a more efficient way to take advantage of competitive opportunities in the electric utility industry. Separating the competitive generation business from the regulated transmission/distribution operations will increase the ability of the system to take advantage of market opportunities and enable each entity to focus its resources on more clearly defined product markets and services.

(ii) Integrated Public Utility System

The electric utility system of PNW is presently "integrated" within the meaning of Section 2(a)(29) of the Act and will remain so after the Reorganization.

The standards that must be met for an electric utility system to be integrated within the meaning of Section 2(a)(29) of the Act are:

(1) the utility assets are to be physically interconnected or capable of physical interconnection and under normal conditions may be economically operated as a single interconnected and coordinated system;

(2) the operations of the system are confined to a single area or region, that is not so large as to impair the advantages of localized management, efficient operation, and the effectiveness of regulation.

The Reorganization will not affect the physical interconnections associated with PNW's existing utility system. All of APS' existing interconnections will remain intact after the Reorganization. The Reorganization will maintain a continuous, geographically compact system with the same physical interconnections as exist today. Similarly, the area of operations of the system will not be affected by the Reorganization and will continue to be primarily confined to a single area (e.g., APS' existing service territory in Arizona) that is not so large as to impair the advantages

of continuing localized management, efficient operation, and effective regulation. See CP&L Energy, Inc., Holding Co. Act Release No. 27188 (June 15, 2000); Central Maine Power Company, et al., Holding Co. Act Release No. 26903 (Aug. 7, 1998).

3. Section 10(f)

Section 10(f) provides that "[t]he Commission shall not approve any acquisition . . . under this Section unless it appears to the satisfaction of the Commission that such State laws as may apply in respect of such acquisition have been complied with, except where the Commission finds that compliance with such State laws would be detrimental to the carrying out of the provisions of Section 11 . . . ."

The Reorganization is conditioned on full compliance with the laws of the Arizona. APS is currently and will remain subject to the jurisdiction of the ACC with respect to the provision of retail electric service. APS and PNW have received the necessary approval from the ACC to proceed with the Reorganization. Copies of this ACC approval is filed as Exhibit D-5 hereto.

For the reasons stated above, the proposed Reorganization meets the standards set forth in Sections 9(a)(2) and 10. The Reorganization involves the first step in the segregation of APS' existing utility assets and operations along functional lines into a wires company and a generation company. The Reorganization will not unduly complicate the capital structure of the PNW system; nor will the Reorganization be detrimental to the public interest, the interests of investors or consumers, or the proper functioning of this system. Also, the Reorganization will yield significant benefits by allowing PNW's public-utility subsidiaries to more effectively compete in the electric utility industry. Therefore, the Commission should by order approve the Reorganization.

B. PNW Will Continue to Claim a Section 3(a)(1) Exemption After the Reorganization.

Section 3(a)(1) of the Act makes an exemption from all of the provisions of the Act, except for Section 9(a)(2), available to a holding company, if "such holding company, and every subsidiary company thereof which is a public-utility company from which such holding company derives, directly or indirectly, any material part of its income, are predominately intrastate in character and carry on their business substantially in a single State in which such holding company and every such subsidiary company thereof are organized." After the Reorganization is complete, PNW and its two public-utility subsidiaries -- APS and PWE -- will be predominantly intrastate in character and will carry on their business substantially in Arizona, the state in which they are all organized.[15] In this regard, PNW will continue to claim an exemption pursuant to Section 3(a)(1) of the Act and Rule 2 of the Commission's regulations, by filing annual exemption statements on Form U-3A-2 following the Reorganization.

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[15] While APS' existing power marketing division was moved to PNW, and continues to perform its power marketing activities on a nationwide basis, PNW's utility operations are still predominately intrastate in character and conducted primarily in Arizona. As noted above, the Commission Staff has indicated in a series of no-action letters that power marketers are not considered "electric utility companies" under Section 2(a)(3) of the Act and, therefore, are not "public-utility companies" under Section 2(a)(5) of the Act. See, e.g., Sunoco Power Marketing, L.L.C., SEC No-Action Letter, 1997 SEC No-Act. LEXIS 785 (July 24, 1997); Enron Capital & Trade Resources Corp., SEC No-Action Letter, 1997 SEC No-Act. LEXIS 287 (Feb. 13, 1997).

ITEM 4 REGULATORY APPROVAL

The Reorganization will require the approval of the ACC and FERC. APS has received an order approving the Reorganization from the ACC, a copy of which is attached hereto as Exhibit D-5. APS also filed an application for approval of the proposed Reorganization with the FERC, a copy of which is attached as Exhibit D-1. A copy of the final FERC order pursuant thereto was filed by amendment on December 8, 2000, as Exhibit D-2. Other than such enumerated approvals and the approval of the Commission hereunder, no other approvals of utility regulatory authorities are required for the Reorganization and the movement of the non-nuclear generating assets to PWE.[16]

ITEM 5 PROCEDURE

PNW respectfully requests that there be no 30-day waiting period between the issuance of the Commission's order and the date on which it is to become effective. PNW also requests that there be no hearing on this application and that the Commission issue its order as soon as practicable after the filing hereof. PNW respectfully requests that the Commission issue and publish the requisite notice under Rule 23 with respect to the filing of this application not later than January 22, 2001, such notice to specify a date not later than February 22, 2001, by which comments may be entered and a date not later than March 1, 2001, as the date after which an order of the Commission granting and permitting this application to become effective may be entered by the Commission. A form of Notice is filed herewith as Exhibit H-1.

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[16] As noted above, approval from the NRC will be obtained in connection with the relocation of APS' nuclear generating facilities to PWE. *See supra* n. 10.

Without prejudice to its right to modify the same if a hearing should be ordered on this application, PNW hereby makes the following specifications required by paragraph (b) of Item 5 of Form U-1:

(1) There should not be a recommended decision by a hearing officer or any other responsible officer of the Commission.

(2) There should not be a 30-day waiting period between issuance of the Commission's order and the date on which the order is to become effective.

(3) PNW consents to the Division of Investment Management assisting in the preparation of the Commission's decision or order in this matter, unless such Division opposes this application.

ITEM 6 EXHIBITS AND FINANCIAL STATEMENTS

It is requested that the Commission send copies of all communications to PNW as follows:

Herbert I. Zinn
Pinnacle West Capital Corporation
400 North Fifth Street
Mail Station 8695
Phoenix, Arizona 85004

Mary Ann K. Huntington
Morgan, Lewis & Bockius LLP
1800 M Street, N.W.
Washington, D.C. 20036

A. Exhibits

Exhibit No.	Description of Document	Method of Filing
A-1	Restated Articles of Incorporation of PNW.	Incorporated by reference; File No. 1-8962, PNW Form 10-K for the year ended December 31, 1999.
A-2	Restated Articles of Incorporation of APS.	Incorporated by reference; File No. 1-4473, APS Form 8-K (Sept. 23, 1993)
A-3	Articles of Incorporation of PWE.	Filed herewith.
B-1	Form of Term Sheet	Filed herewith.
D-1	Application of APS, PNW and PWE to FERC for Authorization to Transfer Jurisdictional Facilities.	Filed herewith.
D-2	Order of FERC.	Filed by amendment on December 8, 2000.
D-3	Retail Electric Competition Rules	Incorporated by reference; file No. 1-4473, filed as Exhibit 10.2 to APS' Sept. 30, 1999 Form 10-Q Report.

D-4	Comprehensive Settlement Agreement Related to the Implementation of Retail Electric Competition, filed with the Arizona Corporation Commission.	Incorporated by reference; File No. 1-4473, filed as Exhibit 10.1 to APS' May 14, 1999 Form 8-K Report.
D-5	ACC Approval of the Settlement Agreement.	Incorporated by reference; File No. 1-4473, filed as Exhibit 10.1 to APS' Sept. 1999 10-Q Report.
D-6	Amended Settlement Agreement	Filed herewith.
E-1	Map showing location of the generating facilities of APS that are being moved to PWE along with their related transmission facilities.	Filed herewith.
F-1	Signed initial opinion of counsel.	Filed by amendment on December 8, 2000.
F-2	Past-tense opinion of counsel.	To be filed by amendment
G-1	PNW, Form U-3A-2, "Statement by Holding Company Claiming Exemption under Rule U-2 from the Provisions of the Public Utility Holding Company Act of 1935."	Incorporated by reference; File No. 69-306, dated Feb. 29, 2000.

H-1	Form of Notice	Filed herewith.

B. **Financial Statements**

Statement No.	Description of Document	Method of Filing
FS-1	Historical consolidated financial statements of PNW	Incorporated by reference to Annual Reports on Form 10-K for the years ended 1999, 1998 and 1997
FS-2	Historical consolidated financial statements of APS	Incorporated by reference to Annual Reports on Form 10-K for the years ended 1999, 1998 and 1997

Although separate financial statements for PWE have not been included, PWE's financial information is included in the consolidated financial statements of PNW.

ITEM 7 INFORMATION AS TO ENVIRONMENTAL EFFECTS

None of the matters that are the subject of this application and declaration involves a "major federal action" nor do any of them "significantly affect the quality of the human environment" as those terms are used in Section 102(2)(C) of the National Environmental Policy Act. The transaction that is the subject of this application will not result in changes in the operation of the company that will have an impact on the environment. Neither APS nor PNW are aware of any federal agency that has prepared or is preparing an environmental impact statement with respect to the transactions that are the subject of this application.

Pursuant to the requirements of the Public Utility Holding Company Act of 1935, the undersigned company has duly caused this Application to be signed on its behalf by the undersigned thereunto duly authorized.

PINNACLE WEST CAPITAL CORPORATION

By: Barbara M. Gomez
Its: Treasurer

Date: January 17, 2001

Phoenix, Arizona

As filed with the Securities and Exchange Commission on April 27, 2001

File No. 070-9745

UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
WASHINGTON, D.C. 20549

AMENDMENT NO. 3 TO
FORM U-1
APPLICATION
UNDER
THE PUBLIC UTILITY HOLDING COMPANY ACT OF 1935

PINNACLE WEST CAPITAL CORPORATION
400 East Van Buren Street, Suite 700
Phoenix, Arizona 85004

(Name of company filing this statement and address of principal executive offices)

None

(Name of top registered holding company parent)

Herbert I. Zinn	**Mary Ann K. Huntington**
Pinnacle West Capital Corporation	**Morgan, Lewis & Bockius LLP**
400 North Fifth Street	**1800 M Street, N.W.**
Mail Station 8695	**Washington, D.C. 20036**
Phoenix, Arizona 85004	

(Name and address of agents for service)

The Commission is requested to send copies of all notices, orders, and communications in connection with this Application to:

Herbert I. Zinn	**Mary Ann K. Huntington**
Pinnacle West Capital Corporation	**Morgan, Lewis & Bockius LLP**
400 North Fifth Street	**1800 M Street, N.W.**
Mail Station 8695	**Washington, D.C. 20036**
Phoenix, Arizona 85004	

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ITEM 7 INFORMATION AS TO ENVIRONMENTAL EFFECTS 35

Pursuant to Sections 9(a)(2) and 10 of the Public Utility Holding Company Act of 1935 (the "Act"), Pinnacle West Capital Corporation, an Arizona corporation ("PNW"), hereby requests approval from the Securities and Exchange Commission (the "Commission") to establish a new public-utility company subsidiary in connection with the proposed corporate reorganization involving the relocation of certain generation assets from Arizona Public Service Company ("APS"), PNW's existing public-utility company subsidiary, to Pinnacle West Energy Corporation ("PWE"), another wholly-owned subsidiary of PNW, (the "Transfer Transaction"), and the operation of PWE's West Phoenix Unit No. 4 as a non-Exempt Wholesale Generator ("EWG") under the Act ("Development Activities"), (collectively, the "Reorganization"). As a result of the Reorganization, PWE will become an "electric utility company" and a "public-utility company" within the meaning of the Act, and, therefore, PNW will acquire an additional public-utility subsidiary. (However, PWE will not become a public service corporation under Arizona state law.) PNW will continue to meet the requirements for an intrastate exemption under Section 3(a)(1) of the Act and will continue to file annual exemption statements on Form U-3A-2 pursuant to Rule 2 of the Commission's regulations.

The purpose of the Reorganization is to comply with certain requirements set forth in rules adopted by the Arizona Corporation Commission ("ACC") that provide the framework for introduction of retail electric competition in Arizona (the "Competition Rules"), and in a final ACC order approving APS' settlement with various parties with respect to implementation of the Competition Rules (the "Settlement"). Pursuant to the Competition Rules and the Settlement, APS must separate its fossil and nuclear generating assets and competitive services, including the development, acquisition and operation of generating facilities not currently owned by APS, from its transmission and distribution functions no later than December 31, 2002. (On February

8, 2001, the ACC issued an order granting APS waiver of this requirement for "solar resources" and "environmentally friendly renewable electricity technologies.") PNW seeks Commission approval now, however, because APS intends to move a substantial portion of its generating assets to PWE during 2001, and PWE is currently involved in the development, acquisition, and operation of other generating facilities that are expected to come online during 2001. In particular, PWE has been developing West Phoenix No. 4, a 120 MW gas-fired combined cycle unit that is now ready to sell test power and go into operation.[1] There may be some delays in moving particular assets from APS to PWE, pending receipt by APS of certain consents or waivers from third parties with respect to such assets, but most of the non-nuclear generating assets are to be moved to PWE during 2001.

[1] As explained below, because West Phoenix No. 4 was prepared to go into operation sooner than previously anticipated, PWE filed an application for an EWG determination with the Federal Energy Regulatory Commission ("FERC") and intends to maintain EWG status only so long as necessary.

ITEM 1 DESCRIPTION OF PROPOSED TRANSACTION

A. Description of the Parties

1. **Pinnacle West Capital Corporation:** PNW was incorporated in 1985 under the laws of the State of Arizona. Through its subsidiaries, PNW is engaged in the generation, transmission, and distribution of electricity and the sale of energy services. Also through subsidiaries, PNW is involved in real estate development and in venture capital investment. On December 31, 2000, PNW employed approximately 7,200 people, including the employees of its subsidiaries. Of these employees, 5,300 were employees of its existing public-utility subsidiary, APS, and employees assigned to joint projects of APS where APS serves as a project manager. PNW's principal executive offices are located at 400 East Van Buren, Phoenix Arizona 85004. PNW is currently a public-utility holding company exempt from the provisions of the Act, except Section 9(a)(2), by reason of its filing of annual exemption statements on Form U-3A-2 pursuant to Rule 2 of the Commission's regulations. 17 C.F.R. § 250.2(a). PNW's direct, wholly-owned subsidiaries are described below and a copy of PNW's most recent Form U-3A-2 is attached as Exhibit G-1.

2. **Arizona Public Service Company:** APS is a public-utility company incorporated in 1920 under the laws of the State of Arizona. APS is a wholly-owned subsidiary of PNW. APS' principal executive offices are located at 400 North Fifth Street, Phoenix, Arizona 85004. APS provides retail electric services principally in the State of Arizona and is actively engaged in the competitive wholesale electric markets. As of December 31, 2000, APS served approximately 850,000 retail electric customers in its service territory. APS is subject to regulation by the ACC with respect to retail rates, accounting, service standards, service territory, issuances of securities, siting of generation and transmission projects and various other matters.

APS is also subject to the jurisdiction of FERC under Parts I, II, and III of the Federal Power Act for certain phases of its business, including regulation of its rates relating to wholesale sales of energy and interstate transmission, licensing its hydroelectric stations, accounting, and certain other matters. APS' current business structure consists of three primary business units: generation; power marketing; and transmission/distribution. The following briefly describes these business units.

a. ***Generation*** – As of December 31, 2000, APS owned or leased generating facilities with a total accredited capacity of approximately 4,000 megawatts. The fuel mix of APS' generation capacity is 41.8% coal; 31.5% gas or oil; 26.5% nuclear; and less than 1% other. APS' sources of energy during 2000 were approximately 54% from its own generation resources and approximately 46% from purchased power. The Reorganization involves the relocation of the ownership interest of a substantial portion of APS' generating facilities and related facilities, as well as the transfer of certain of the employees of APS' generation business unit.[2] Attached, as Exhibit E-1, is a map showing the location of each of APS' generation facilities. As of December 31, 2000, the APS generating assets being moved to PWE during 2001 can be described as follows:[3]

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[2] Because of anticipated decommissioning activities, APS intends to retain its interest in the Childs-Irving plant, a hydroelectric generating plant with a total accredited capacity of approximately 3 megawatts. In addition, the ACC's February 8, 2001 order contemplates that APS will retain ownership interests in its solar and environmentally friendly renewable resource generating plants. The total accredited capacity from these units is approximately 1 megawatt.

[3] In addition to the generating facilities to be moved during 2001, APS also owns or leases an interest in the Palo Verde Nuclear Generating Station ("PVNGS"), a three-unit nuclear generating facility located in Wintersburg, Arizona approximately 55 miles west of Phoenix, Arizona. The total accredited capacity of PVNGS is 3,733 megawatts, of which APS owns or leases 29.1%, or approximately 1,086 megawatts. APS is also the operator of the facility. There are six other co-owners of PVNGS, which collectively own or lease the remaining 70.9%. Ownership is in the form of a co-tenancy, and the co-owners are not affiliates of one another. APS operates PVNGS pursuant to an agreement in which each owner pays its proportionate share of the cost of operating the facility. While the Transfer Transaction involving APS' fossil generating facilities is contemplated to occur during 2001, APS does not plan to move its interest in PVNGS to PWE until 2002. The delay in moving the nuclear assets

Four Corners Power Plant ("Four Corners"):

Four Corners is a five-unit coal fired power plant located near Farmington, New Mexico on the Navajo Reservation. The property underlying the plant is held under easements granted by the federal government and under leases from the Navajo Nation. Units 1, 2 and 3 have an accredited capacity of 560 megawatts. These units are 100% owned and operated by APS. Units 4 and 5 have an accredited capacity of 1,480 megawatts; APS owns 15% of units 4 and 5, or 222 megawatts. The remaining interests in units 4 and 5 are co-owned by five other entities. Ownership of units 4 and 5 is through a co-tenancy arrangement, and the co-owners are not affiliates of one another. APS operates Four Corners units 4 and 5 pursuant to an agreement in which each owner pays its proportionate share of the operating cost.

Cholla Power Plant ("Cholla"):

Cholla is a four-unit coal-fired power plant located in Navajo County approximately 200 miles northeast of Phoenix, Arizona. Units 1, 2 and 3 have an accredited capacity of 615 megawatts. These units are 100% owned and operated by APS. Unit 4 has an accredited capacity of 380 megawatts; unit 4 is 100% owned by another unaffiliated entity. APS is also the operator for this unit.

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is to ensure additional time to adequately address complicated contractual arrangements, such as sale and leaseback provisions between APS and certain owner trusts to which APS has sold and leased back a portion of its interest in PVNGS Unit 2 and the PVNGS common facilities. There are also certain financial and economic considerations that must be resolved before the nuclear assets can be moved to PWE.

Navajo Power Plant ("Navajo"):

Navajo is a three-unit coal-fired plant located south of Page, Arizona. The total accredited capacity for the plant is 2,250 megawatts. APS owns 14%, or 315 megawatts of this plant. The remaining interests in the plant are co-owned by five other entities which are not affiliated with APS. APS does not operate Navajo.

Saguaro Power Plant ("Saguaro"):

Saguaro is a four-unit power plant consisting of two gas/oil-fired steam units and two gas/oil-fired combustion turbine units and is located 30 miles north of Tucson, Arizona. The total accredited capacity for the plant is 319 megawatts. Steam units 1 and 2 have a combined capacity of 209 megawatts, and the two combustion turbines have a combined capacity of 110 megawatts. This plant is 100% owned and operated by APS.

Ocotillo Power Plant ("Ocotillo"):

Ocotillo is a multi-fueled generating plant located in Tempe, Arizona. Two units are gas/oil-fired steam units, and two units are gas/oil-fired combustion turbines.[4] The total accredited capacity for steam units 1 and 2 is 226 megawatts and for combustion turbine units 1 and 2, the accredited capacity is 110 megawatts. This plant is 100% owned and operated by APS.

Yucca Power Plant ("Yucca"):

Yucca is a five-unit gas/oil combustion turbine plant located near Yuma, Arizona. The accredited capacity of units 1, 2, 3 and 4 is 147 megawatts. These units are 100% owned and operated by APS. Unit 5 and a separate steam unit are owned by a separate, unaffiliated entity but operated by APS.

West Phoenix Power Plant ("West Phoenix"):

West Phoenix is an eight-unit gas/oil-fired steam, combustion turbine, and combined cycle generation plant located in Phoenix, Arizona. Combustion turbine units 1 and 2 have an accredited capacity of 110 megawatts; combined cycle units 1, 2 and 3 have an accredited capacity of 255 megawatts; and steam units 4, 5 and 6 have an accredited capacity of 108.3 megawatts. APS owns and operates 100% of West Phoenix and is entitled to 100% of the output.

Douglas/Fairview Power Plant:

Douglas/Fairview is a single combustion turbine unit with a capacity rating of 16 megawatts located near Douglas, Arizona. Douglas/Fairview is 100% owned and operated by APS.

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[4] There are also three solar units at Ocotillo; however, these units will remain with APS.

b. ***Power Marketing*** -- APS' Power Marketing and Trading division ("Power Marketing") primarily engages in the sale and purchase of electric capacity and energy in the wholesale market. Power Marketing sells excess power from APS' generation facilities and also purchases energy from other entities to meet APS' requirements to supply retail and wholesale customers. Power Marketing also engages in hedging transactions in forward markets for electricity and fuel and in the purchase and sale of emission allowances as part of APS' effort to manage risks associated with its generation and distribution activities. The ACC Competition Rules and Settlement contemplate that as a competitive asset, APS would also move its Power Marketing division to an affiliate. Accordingly, on October 1, 2000, Power Marketing became a division of PNW.[5]

c. ***Transmission/Distribution*** -- APS owns and operates approximately 5,296 miles of transmission lines, of which all but 140 miles are located within the State of Arizona.[6] APS' transmission was built primarily to bring generation from its power plants to its retail electric loads in Arizona. Ownership and operation of APS' transmission facilities is subject to regulation by FERC. Transmission rates are prescribed by FERC and the use of and

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[5] PNW itself did not become an electric utility company when this occurred. The Commission and Staff have both recognized, on numerous occasions, that marketing activities are not utility activities under the Act. See, e.g., UNITIL, Holding Company Act Release No. 26650 (Jan. 21, 1997); SEI Holdings, Inc., Holding Company Act Release No. 26581 (Sept. 26, 1996); Sunoco Power Marketing, L.L.C., SEC No-Action Letter, 1997 SEC No-Act. LEXIS 785 (July 24, 1997); Enron Capital & Trade Resources Corp., SEC No-Action Letter, 1997 SEC No-Act. LEXIS 287 (Feb. 13, 1997); Eastex Power Marketing, Inc., SEC No-Action Letter, 1996 SEC No-Act. LEXIS 536 (Apr. 30, 1996); LG&E Power Marketing, Inc., SEC No-Action Letter, 1996 SEC No-Act. LEXIS 510 (Apr. 26, 1996); Coral Power, L.L.C., SEC No-Action Letter, 1996 SEC No-Act. LEXIS 314 (Feb. 22, 1996); AIG Trading Corp., SEC No-Action Letter, 1995 SEC No-Act. LEXIS 195 (Jan. 20, 1995); Inter-Coast Power Marketing Co., SEC No-Action Letter, 1994 SEC No-Act. LEXIS 886 (Dec. 6, 1994); Electric Clearinghouse, Inc., SEC No-Action Letter, 1994; SEC No-Act. LEXIS 452 (Apr. 13, 1994); CRSS Power Marketing, Inc., SEC No-Action Letter, 1994 SEC No-Act. LEXIS 431 (Mar. 31, 1994).

[6] Specifically, as of December 31, 2000, APS' transmission system included approximately 1,627 miles of 500 kV transmission, 578 miles of 345 kV transmission, 594 miles of 230 kV transmission, 176 miles of 115 kV transmission, and 2,321 miles of 69 kV transmission.

access to the transmission system is subject to FERC's open access requirements set forth in FERC Order No. 888. As of December 31, 2000, APS' distribution system included approximately 23,000 miles of distribution line and served approximately 850,000 electric retail customers in its service territory within the State of Arizona. APS provides distribution services in 11 of Arizona's 15 counties, including the metropolitan Phoenix area. Pursuant to the Settlement approved by the ACC in 1999, which is more fully discussed below, retail rates have been set until July 1, 2004, subject to conditions or circumstances which constitute an emergency. APS' transmission and distribution business will remain with APS under the Reorganization.

3. **Pinnacle West Energy Corporation:** PWE was incorporated in Arizona on September 27, 1999 under the laws of the State of Arizona. PWE is a wholly-owned subsidiary of PNW. PWE was organized primarily to engage in the business of developing, owning, and operating generation plants used for the production and sale of wholesale energy. As of December 31, 2000, PWE was engaged in the development of approximately 2,600 megawatts of generating capacity in the State of Arizona and operations in other states are contemplated, too; however, PWE is not currently an electric utility company or a public-utility company within the meaning of the Act.

Upon consummation of the Reorganization described herein and the subsequent relocation of APS' nuclear generating facilities, PWE will own or lease the generation facilities currently owned or leased by APS and will assume APS' responsibilities as operator of the facilities described above, with the exception of the Navajo Generating Station, which will continue to be operated by another, unaffiliated entity.

On March 28, 2001, PWE filed an application with FERC for EWG status. PWE's EWG application describes PWE's "eligible facility" as a 100% ownership and operating interest in West Phoenix Unit No. 4 ("West Phoenix No. 4"), a newly constructed natural gas-fired, combined cycle unit with a nominal power output of 120 MW located on the site of APS's West Phoenix Plant. At the time PNW filed its original Application for Commission approval under Section 9(a)(2), it was not anticipated that West Phoenix No. 4 would be completed and prepared to go into operation prior to completion of the Transfer Transaction involving APS' fossil generating facilities. However, due to the recent energy shortages in the West, PWE accelerated the development of West Phoenix No. 4, which is now ready to provide test power and go into operation, and filed its application for EWG status. PWE will limit its activities to EWG activities until the Commission issues its order authorizing PWE to become a public-utility company subsidiary of PNW. At that time, PWE plans to inform FERC that it no longer intends to operate as an EWG.[7]

PWE's principal place of business is 400 North Fifth Street, Phoenix, Arizona 85004.

4. APS Energy Services Company, Inc. ("APSES"): APSES is an Arizona corporation formed in 1998. APSES is a wholly-owned subsidiary of PNW. APSES was organized as a retail power marketer to provide retail energy and related retail energy services to customers throughout Arizona, California, and other states that have instituted retail direct access. APSES does not own or control electric power generation, transmission, or distribution facilities.[8] APSES' principal place of business is 400 East Van Buren Street, Phoenix, Arizona.

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[7] In addition, to the extent necessary for PNW to maintain its intrastate exemption, PWE may establish EWG subsidiaries to own and/or operate future assets that may be located out of state.

[8] APSES is not an "electric utility company" or a "public-utility company" as those terms are defined in the Act. See, e.g., Enron, SEC No-Action Letter (1997).

5. SunCor Development Company ("SunCor"): SunCor was incorporated in 1965 under the laws of the State of Arizona. SunCor is a wholly-owned subsidiary of PNW. SunCor is engaged in commercial and residential real estate development. SunCor is not engaged in generating, transmitting, distributing or selling electric energy and will not be affected by the Reorganization. SunCor's principal place of business is 3838 North Central, Suite 1500, Phoenix, Arizona 85012.

6. El Dorado Investment Company ("El Dorado"): El Dorado was incorporated in 1983 under the laws of the State of Arizona. El Dorado is an investment company and wholly-owned subsidiary of PNW. El Dorado is not engaged in the business of generating, transmitting, distributing, or selling electric energy and will not be affected by the Reorganization. El Dorado's principal place of business is 400 East Van Buren Street, Suite 800, Phoenix, Arizona 85004.

B. Regulatory Background

The Reorganization is being undertaken in accordance with the Competition Rules and Settlement. Specifically, in Arizona, the ACC has adopted the Competition Rules to expedite the transition to retail electric competition. Among other things, the Competition Rules required that APS separate its fossil and nuclear generation assets and competitive business activities from its transmission and distribution functions and to develop, acquire and operate additional generation outside of APS. In 1999, the ACC approved the Settlement between APS and several customer groups and consumer advocates resolving retail electric competition-related issues and approving unbundled tariffs.[9] The order found that the Settlement is in the public interest because it

[9] The ACC order approving the Settlement is attached as Exhibit D-5.

provides "for competitive retail access in APS' Service Territory, establishes rate reductions for all APS customers, [and] sets a mechanism for stranded cost recovery."[10]

Under the terms of the Competition Rules and the Settlement, retail choice for APS' retail customers is being phased-in. As of January 1, 2001, all of APS' retail customers are entitled to choose their retail power supplier.[11] The retail rates of customers that continue to take fully bundled service from APS and do not choose an alternative supplier will be subject to planned rate reductions that will continue until July, 2004.[12] Under the Settlement, APS is entitled to apply for a change in the agreed upon rate reductions only in the event of an emergency or a material change in its cost of service as a result of specified extraordinary events. The Settlement also requires APS to complete separation of its fossil and nuclear generation assets by December 31, 2002.[13]

C. The Reorganization

As previously mentioned, APS and PWE are both currently direct, wholly-owned subsidiaries of PNW. APS and PWE will be the only two "public-utility company" (as defined in the Act) subsidiaries of PNW upon the completion of the activities described in this Application.

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10 See Exhibit D-5.

11 See Exhibit D-5.

12 See Exhibit D-4.

13 See Exhibit D-4. As noted above, APS is not required to separate its solar resources and "environmentally friendly renewable electricity technologies" from its transmission/distribution functions.

PNW and APS propose to transfer APS' fossil generating facilities pursuant to the arrangements described in the Term Sheet,[14] attached as Exhibit B-1 hereto. In connection with the Transfer Transaction, it is contemplated that the following transactions will occur during 2001: First, APS will contribute all of its fossil generating facilities, assets and related operational agreements, to one or more of these newly-formed subsidiaries (hereafter "Transitory Subsidiaries") which will be wholly-owned by APS. This transaction is intended to qualify as a tax-deferred reorganization under Internal Revenue Code ("IRC") Section 368(a)(1)(D). Second, APS will distribute or cause to be distributed all of the stock of each Transitory Subsidiary to PNW in a transaction intended to qualify as a tax-deferred spin-off under IRC Section 355. Third, under state law, the Transitory Subsidiaries will then be merged into PWE (with PWE as the surviving entity) in a transaction intended to qualify as a tax-deferred statutory merger under IRC Section 368(a)(1)(A). It is contemplated that the three aforementioned transactions will occur simultaneously.

When the Reorganization is complete and APS' nuclear generating assets have been moved to PWE, APS' existing divisional structure in which its electric utility operations are divided along functional lines will be formalized, and separate corporate entities will own the transmission/distribution facilities and the fossil and nuclear generating assets. APS will become essentially a "wires" company and continue to own and operate its existing electric transmission/distribution system,[15] and PWE will become a "generating" company and will own or lease and operate the existing fossil and nuclear generation plants and other generation

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[14] Although the term sheet indicates that the transfer of assets will take place "on or before January 1, 2001," it is now contemplated to occur during 2001.

[15] APS will also continue to own its solar and renewable resource generating assets.

facilities it develops, or acquires in the future, and sell the output from these plants and other facilities at wholesale to Power Marketing. Power Marketing, in turn, is expected then to sell power to APS and other non-affiliated power purchasers. APS will continue to provide transmission and distribution services at regulated rates, as well as provide energy to those retail customers in APS' existing service territory that do not elect to use an alternate retail power supplier. A diagram of PNW's corporate structure, after the Transfer Transaction is complete and the nuclear generating facilities have been moved to PWE, is shown on Appendix B to Exhibit D-1 attached hereto.

The Transfer Transaction is subject to certain conditions as stated in the Term Sheet attached as Exhibit B-1. Principally, these conditions include: (a) the approval of the Commission under Section 9(a)(2) of the Act; (b) approvals of FERC under Sections 203 and 205 of the Federal Power Act 16 U.S.C. §§824b and d (1994); and (c) consents and waivers of certain third parties with respect to contracts associated with the generation assets. The approval of the ACC has already been granted.[16] No PNW shareholder approval is required in connection with the Transfer Transaction. Although APS does not believe that shareholder approval is required for the Transfer Transaction, the approval of its sole shareholder was obtained on November 15, 2000.[17] The approval of APS' Board of Directors was also obtained on November 15, 2000.

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[16] Approval from the Nuclear Regulatory Commission ("NRC") will be obtained in connection with the movement of APS' interest in its nuclear generating assets, which will occur by year-end 2002. No NRC approval, however, is necessary in connection with the Transfer Transaction involving APS' fossil generating facilities. Approval of some plant participants may also be required.

[17] As a wholly-owned subsidiary of PNW, APS' only shareholder is PNW.

No approval, other than the approval of the Commission under Section 9(a)(2), is necessary in connection with the Development Activities.[18]

D. Purpose and Anticipated Effects of the Reorganization

The principal purpose of the Reorganization and the subsequent relocation of APS' nuclear generating facilities to PWE is to assure compliance with the provisions of the Competition Rules and the Settlement and provide PNW with increased financial, managerial, and organizational flexibility which will enable APS and PWE to effectively compete in a restructured utility industry.

After extensive investigation and analysis, PNW has determined that the proposed Reorganization offers the best means of positioning the PNW system for future changes and opportunities and will enable PNW to take advantage of emerging business opportunities and manage risks to the benefit of both shareholders and customers. The Reorganization is the first step in a clear functional and corporate separation between PNW's competitive generation business, and its distribution and transmission business, enabling each company to focus its resources on more clearly defined product markets and services. The intent of the Reorganization and subsequent relocation of APS' nuclear generating facilities is to create a financially sound and responsive utility system which can provide utility services effectively and efficiently. Additionally, the corporate division along functional lines will provide a better structure for regulators to assure that there is no cross-subsidization of costs or transfer of business risk from the competitive generation business to the fully-regulated

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[18] As noted above, PWE has filed with FERC an application for EWG status in connection with its Development Activities. In addition, although PWE's Development Activities may involve various siting, environmental, or other approvals, all of the approvals in connection with PWE's operation of West Phoenix No. 4 have already been obtained.

transmission/distribution business. Moreover, this type of corporate division of utility assets and operations along functional lines is becoming a highly-desirable form of conducting both a regulated transmission/distribution business and a competitive generation business.

The Reorganization will have no adverse effect on APS' existing electric utility operations. The Reorganization will not cause substantive changes in PNW's ultimate interest in existing utility businesses and will not involve the transfer or acquisition of any additional utility assets beyond those currently held by APS or those which have been developed by PWE. The managers and employees in PNW's existing utility operations will continue to perform their existing functions -- either as employees of APS, the transmission/distribution company, or as employees of PWE, the generating company. Thus, even though day-to-day utility operations would not be affected, the benefits discussed above will accrue to PNW and its customers and shareholders as a result of the Reorganization and the subsequent relocation of APS' nuclear generating facilities to PWE.

E. Additional Information

No associate company or affiliate of PNW or APS, or any affiliate of any associate company of PNW or APS, has any direct or indirect material interest in the proposed Reorganization except as stated herein.

ITEM 2 FEES, COMMISSIONS AND EXPENSES

The fees, commission and expenses to be paid or incurred by PNW and APS in connection with the federal regulatory approvals required in connection with the Reorganization and the establishment of PWE are estimated as follows:

Auditors' Fee	$ 10,000.00
Legal Fees	$ 400,000.00
Total	$ 410,000.00

In addition, there will also be certain other costs associated with the transfer of APS' generating assets to PWE; these costs, which will include fees for financial consulting, asset valuation, and engineering reports, as well as additional legal fees, are estimated not to exceed $1.5 million.

ITEM 3 APPLICABLE STATUTORY PROVISIONS

Sections 9(a)(2) and 10 of the Act are applicable to the proposed Reorganization. As a result of the proposed Reorganization,[19] PNW will have two wholly-owned, public-utility company subsidiaries, APS and PWE. Section 9(a)(2) of the Act requires Commission approval before a person may acquire more than 5% of the outstanding voting securities of more than one "public-utility company." The standards for approval of a transaction under Section 9(a)(2) of the Act are set forth in Section 10 of the Act. The relevant standards under Section 10 are set forth in Section 10(b), 10(c) and 10(f).

For the reasons explained below, the Commission should approve this Application pursuant to Section 9(a)(2) of the Act because it complies with the applicable standards of Section 10. PNW respectfully requests that the Commission issue an order approving the Reorganization by May 1, 2001. As noted above, PWE has already filed an application with FERC for EWG status and intends to limit its activities exclusively to the ownership and operation of eligible facilities and sale of power at wholesale in order to maintain EWG status

[19] At this time, it is not entirely clear whether it is the Transfer Transaction or the Development Activities that will cause PWE to become a public-utility company. As noted above, PWE has applied to FERC for EWG status because West Phoenix No. 4 will be prepared to sell test power prior to the date of a Commission order authorizing PWE to become a public-utility company. Once the Commission issues its order, however, PWE intends to inform FERC that it will no longer maintain EWG status. Thus, PNW seeks authorization for PWE to become a public-utility company the earlier of (1) the date PWE notifies FERC that it no longer intends to maintain EWG status or (2) the date the Transfer Transaction is consummated.

until the Commission issues an order approving this Application. Because EWG status limits PWE's activities to those "incidental" to the ownership and operation of eligible facilities, PWE is eager to become a public-utility company as soon as possible in order to have broader flexibility in addressing the needs of the electric power market.

A. Approval of the Reorganization under Section 9(a)(2).

Section 9(a)(2) makes it unlawful, without approval of the Commission under Section 10, "for any person . . . to acquire, directly or indirectly, any security of any public-utility company, if such person is an affiliate . . . of such company and of any other public utility or holding company, or will by virtue of such acquisition become such an affiliate." By virtue of the proposed Reorganization, PNW will own more than 5% of the outstanding voting securities of two "public-utility companies" (APS and PWE) thus becoming an affiliate of both of these public-utility companies. Under Section 2(a)(5) of the Act, a "public-utility company" is an "electric utility company" or a "gas utility company." Under Section 2(a)(3) of the Act, an "electric utility company" is defined as "any company which owns or operates facilities used for the generation, transmission, or distribution of electric energy for sale . . . ." Upon completion of the Reorganization, PWE will own and operate certain of APS' existing facilities for the generation of electric energy for sale, as well as West Phoenix No. 4 and other generating assets to be developed or acquired by PWE in the future, and APS will continue to own and operate its existing facilities for the transmission and distribution of electric energy for sale, as well as its nuclear, solar, and hydroelectric generating facilities. Therefore, both PWE and APS will be public-utility companies within the meaning of the Act.

1. Section 10(b)

Section 10(b) provides that the Commission shall approve an acquisition pursuant to Section 9(a)(2) unless the Commission finds that:

(1) such acquisition will tend towards interlocking relations or the concentration of control of public-utility companies, of a kind or to an extent detrimental to the public interest or the interest of investors, or consumers;

(2) in case of the acquisition of securities or utility assets, the consideration, including all fees, commissions, and other remuneration, to whomsoever paid, to be given, directly or indirectly, in connection with such acquisition is not reasonable or does not bear a fair relation to the sums invested in or the earning capacity of the utility assets to be acquired or the utility assets underlying the securities to be acquired; or

(3) such acquisition will unduly complicate the capital structure of the holding-company system of the applicant or will be detrimental to the public interest or the interest of investors or consumers or the proper functioning of such holding-company system.

PNW respectfully submits that no adverse findings should be made under any of these provisions.

a. "Detrimental Interlocking Relations" or "Concentration of Control" -- Section 10(b)(1)

Consistent with Section 10(b)(1) of the Act, PNW submits that the Reorganization will not tend towards interlocking relations or the concentration of control of public-utility companies, of a kind or to an extent detrimental to the public interest or the interest of investors or customers. The Reorganization involves the first step in the ultimate segregation of APS' existing utility assets and operations along functional lines into a generation company (PWE) and a transmission and distribution company (APS).

While there may be certain common directors and officers of PNW and the public-utility subsidiaries, these relations normally exist in public-utility holding company systems among affiliated and associated companies and should not be considered detrimental to the public interest or the interest of investors or consumers. See Central Maine Power Company, et al., Holding Co. Act Release No. 26903 (Aug. 7, 1998); CIPSCO, Inc., Holding Co. Act Release No. 25152, 47 SEC Docket 174 (Sept. 18, 1990).

Similarly, the Reorganization should not, within the meaning of Section 10(b)(1), be deemed to tend towards any "concentration of control of public-utility companies" that might be detrimental to the public interest, consumers or investors. The Reorganization will not involve the acquisition or control of any utility assets or operations which are not already owned or controlled by PNW or its existing public-utility subsidiary, APS, or being developed by PWE, and "will therefore have no effect on the concentration of control of public-utility companies." Central Maine Power Company, et al., Holding Co. Act Release No. 26903 (Aug. 7, 1998); accord BEC Energy, et al., Holding Co. Act Release No. 26874 (May 15, 1998); Energy East

Corp., Holding Co. Act Release No. 26834 (March 4, 1998); Wisconsin Energy Corp., Holding Co. Act Release No. 24267 (Dec. 18, 1996).

b. Fairness of Consideration and Fees -- Section 10(b)(2)

Section 10(b)(2) of the Act requires the Commission to determine whether the consideration paid in connection with a proposed acquisition of securities is reasonable and bears a fair relation to the investment in and earning capacity of the utility assets underlying the securities being acquired.

The generating assets being moved as part of the Transfer Transaction will be recorded on the books of PWE at net book value. In addition, PWE will assume certain outstanding debt associated with the generating assets being moved. However, in order to maintain APS' current debt to common stock equity ratio,[20] PNW will not move all of the outstanding debt associated with the generating assets to PWE. The valuation of PNW's investment in the securities of PWE and APS will be adjusted accordingly to reflect the movement of these assets and the associated debt to PWE.[21]

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[20] As of December 31, 2000, APS' debt to Common Stock equity ratio was 49%/51%. The Reorganization is being structured so that this ratio will remain the same after the Reorganization.

[21] Specifically, PWE will assume APS' rights and obligations with respect to approximately $180 million in pollution control bonds issued by Navajo County, Arizona, Pollution Control Corporation and Coconino County, Arizona, Pollution Control Corporation. These two series of bonds were issued by the respective pollution control corporations under two separate Indentures of Trust dated as of August 1, 1993 between the issuer and an independent trustee. In each case, the issuer loaned the proceeds of the bonds to APS under a Loan Agreement dated as of August 1, 1993, and APS is responsible to repay the loan by making payments on the bonds when due. APS' obligations are secured by First Mortgage Bonds issued by APS and delivered to the Trustee for the pollution control bonds. At the time generating assets are moved to PWE, APS will assign its rights and obligations under the Loan Agreements to PWE, and PWE will assume such obligations. APS will remain primarily liable for such obligations and the First Mortgage Bonds will remain outstanding.

PWE will also assume APS' obligations under another approximately $60 million of pollution control bond debt, releasing APS from such obligations. No bondholder consent is required in connection with PWE's assumption of this debt. However, APS must give advance notice to the bondholders and any bondholder who does not wish to continue to hold the bonds may tender its bonds for purchase. In addition, if the issuance of a new letter of credit in substitution for the existing letter of credit supporting the bonds causes the ratings on the bonds to be

Since the Transfer Transaction involves an entirely intra-company movement of existing assets from one wholly-owned subsidiary to another, PNW believes that the valuation established for purposes of this asset transition is reasonable and bears a fair relationship to the sums invested in the assets. PNW, as the sole owner of both APS and PWE, can expect to earn a fair return on its investment in APS and its investment in PWE.

An estimate of the fees and expenses to be paid in connection with the Reorganization is stated in Item 2 above. Such fees and expenses will be reasonable and customary for transactions of this kind and will not be material when measured against PNW's consolidated book value or the earning capacity of its assets. See, e.g., Madison Gas and Electric Co., Holding Co. Act Release No. 27326 (Dec. 28, 2000); WPS Resources Corp., Holding Co. Act Release No. 27330 (Dec. 28, 2000); Energy East Corp., Holding Co. Act Release No. 27128 (Feb. 2, 2000).

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lower than the existing rating, the bonds will be subject to a mandatory tender on the substitution date, and all the bonds will be subject to mandatory repurchase and remarketing on that date.

c. Complication of Capital Structure -- Section 10(b)(3)

Section 10(b)(3) of the Act requires the Commission to determine whether the transaction will unduly complicate the capital structure of the PNW system, be detrimental to the public interest, the interest of the investors or consumers, or the proper functioning of the holding-company system. No such effect will result from the Reorganization.

The Reorganization will not involve the creation of any ownership interests other than those necessary to maintain the basic corporate relationships of the reorganized holding-company system. PNW will continue to be the only issuer of publicly owned equity securities in the system. PNW will continue to own all of the outstanding common stock of PWE, APS, and PNW's existing non-utility subsidiaries; there will be no minority equity interest in any of PNW's public-utility subsidiaries. As noted above, certain pollution control bonds issued by APS will be assumed by PWE, but this will in no way complicate the capital structure of PNW, APS, or PWE. This type of capital structure is typical of a contemporary holding company system and is within the traditional standards of the Act.

Moreover, the Reorganization is a significant step toward the ultimate goal of creating separate entities to perform PNW's transmission/distribution business and its generation business in compliance with the ACC's Competition Rules and the Settlement. Consequently, because the Reorganization does not complicate the capital structure of PNW, APS, or PWE, the standards of Section 10(b)(3) of the Act are satisfied.

2. Section 10(c)

The relevant provisions of Section 10(c) of the Act state that the Commission shall not approve:

> (1) an acquisition of securities or utility assets, or of any other interest, which is unlawful under the provisions of Section 8 or is detrimental to the carrying out of the provisions of Section 11; or
>
> (2) the acquisition of securities or utility assets of a public-utility or holding company unless the Commission finds that such acquisition will serve the public interest by tending towards the economical and the efficient development of an integrated public-utility system . . . .

APS and PNW respectfully submit that no adverse determination should be made under either of these provisions.

a. Significant Benefits -- Section 10(c)(1)

Section 10(c)(1) prohibits an acquisition of securities which is "unlawful under the provisions of Section 8" or "detrimental to the carrying out of the provisions of Section 11." By their express terms, Sections 8 and 11 apply only to registered holding companies and do not apply to exempt holding companies. After the Reorganization, PNW will continue to be exempt from all provisions of the Act, except Section 9(a)(2), pursuant to Section 3(a)(1) of the Act since PNW and its utility subsidiaries, APS and PWE, will each be predominantly intrastate in character, carry on their businesses substantially in Arizona, and be organized in Arizona. Accordingly, Section 8 of the Act is inapplicable to the Reorganization.

For the purposes of the Commission's review of the proposed reorganization of a holding company, the relevant provision of Section 11 is Section 11(b)(2), which requires the Commission to find that "the corporate structure . . . of any company in the holding-company system does not unduly or unnecessarily complicate the structure . . . of such holding-company system." In that connection, the Commission has construed this requirement, "to mean that the structural change must result in significant benefits to the holding-company system." CIPSCO Inc., Holding Co. Act Release No. 25152, 47 SEC Docket at 178 (Sept. 18, 1990); accord Central Maine Power Company, et al., Holding Co. Act Release No. 26903 (Aug. 7, 1998); BEC Energy, et al., Holding Co. Act Release No. 26874 (May 15, 1998); Energy East Corp., Holding Co. Act Release No. 26834 (March 4, 1998).

As discussed above in Section D of Item 1, the corporate structure resulting from the Reorganization will yield significant benefits. Most importantly, the Reorganization and subsequent movement of APS' nuclear generating facilities to PWE will enable APS to implement the requirements of ACC Competition Rules and Settlement. In particular, as the ACC noted in its order on the Settlement, the Settlement provides for competitive retail access in APS' service territory, establishes rate reductions for all APS customers, sets a mechanism for stranded cost recovery, and is in the public interest.[22] In addition, segregation of the separate utility functions into separate corporations dedicated solely to those functions will: (1) enable the executives, officers, and managers of APS and PWE to concentrate on the delivery of cost efficient and effective utility services responsive to the needs of customers; (2) allow PNW's subsidiaries and affiliates to be more competitive in their businesses; (3) segregate the financial

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[22] See Exhibit D-5.

and legal risks associated with those businesses; (4) ensure that there is no cross-subsidization of costs or business risk; and (5) aid the investment community in analyzing and valuing individual lines of business. In cases involving corporate reorganizations or the formation of holding companies, the Commission has held that the existence of these kinds of potential benefits satisfies the statutory standard of Section 10(c)(1). See, e.g., Central Maine Power Company, Holding Co. Act Release No. 26903 (Aug. 7, 1998); Atlanta Gas Light Company, Holding Co. Act Release No. 26482, 61 SEC Docket 1057 (March 5, 1996); SIGCORP, Inc., Holding Co. Act Release No. 26431, 60 SEC Docket 90 (Dec. 14, 1995); PP&L Resources, Inc., Holding Co. Act Release No. 26248, 58 SEC Docket 2634 (March 10, 1995); CIPSCO Inc., Holding Co. Act Release No. 25152, 47 SEC Docket 174 (Sept. 18, 1990); Wisconsin Energy Corp., Holding Co. Act Release No. 24267 (Dec. 18, 1996).

b. Economics and Efficiencies of an Integrated System – Section 10(c)(2)

Under Section 10(c)(2), the Commission must find that the Reorganization tends towards the economical and efficient development of an integrated public utility system. PNW respectfully submits that this standard is met in this case.

(i) Economics and Efficiencies

A number of economies and efficiencies will result from the PNW structure. Some of these benefits are described in Section D of Item 1 and Section A.2.a of Item 3, above. Overall, the Reorganization will permit a more efficient way to take advantage of competitive opportunities in the electric utility industry. Separating the competitive generation business from the regulated transmission/distribution operations will increase the ability of the system to take advantage of market opportunities and enable each entity to focus its resources on more clearly defined product markets and services.

(ii) Integrated Public Utility System

The electric utility system of PNW is presently "integrated" within the meaning of Section 2(a)(29) of the Act and will remain so after the Reorganization.

The standards that must be met for an electric utility system to be integrated within the meaning of Section 2(a)(29) of the Act are:

(1) the utility assets are to be physically interconnected or capable of physical interconnection and under normal conditions may be economically operated as a single interconnected and coordinated system;

(2) the operations of the system are confined to a single area or region, that is not so large as to impair the advantages of localized management, efficient operation, and the effectiveness of regulation.

The Commission has previously taken notice of recent developments in the electric industry and has interpreted the Act and analyzed proposed transactions in light of these changed and changing circumstances. See, e.g., American Electric Power Co., Holding Co. Act Release No. 27186 (Jun. 14, 2000) ("AEP Order"); New Century Energies, Inc., Holding Co. Act Release No. 26748 (Aug. 1, 1997) (citing Hearing on Regulation of Public Utility Holding Companies Before Subcomm. on Telecommunications and Finance and Subcomm. on Energy and Power of

the House of Representatives Comm. on Commerce, 104th Cong., 1st Sess. (Aug 4, 1995) (testimony of Arthur Levitt, Chairman, SEC)). See also Rust v. Sullivan, 500 U.S. 173, 186-87 (1991) ("an agency is not required to 'establish rules of conduct to last forever,'" "but rather must be given ample latitude to 'adapt [its] rules and policies to the demands of changing circumstances.'") (citations omitted).

The Settlement and ACC Order introducing retail competition and requiring the separation of the regulated transmission/distribution business from the competitive generation and marketing businesses constitute the type of "changing circumstance" which the Commission should consider in evaluating the proposed Reorganization. In addition, FERC has recognized that in order to foster competitive electric markets, the operation of transmission facilities should be functionally unbundled from the generation business and/or transferred to an entirely separate corporate entity. The proposed Reorganization is consistent with these goals.

When the Reorganization is complete, and APS has moved its nuclear generating assets to PWE, APS will be in compliance with the ACC Order and Settlement. Yet, the Reorganization will not affect the physical interconnections or coordinated operations associated with PNW's existing utility system. All of APS' existing interconnections will remain intact. A continuous, geographically compact system, with the same physical interconnections as exist today, will be maintained.

Moreover, although the Reorganization, for the most part, will unbundle the transmission/distribution business from the generation business from a financial perspective, the Reorganization will not affect coordination from an operational perspective. The generation and/or flow of power within the system will continue to be centrally controlled and dispatched as need or economy dictates. See, e.g., WPS Resources Corp., Holding Co. Act Release No. 27330

(Dec. 28, 2000); UNITIL, Holding Co. Act Release No. 25524 (Apr. 24, 1992). Currently, economic dispatch of units is performed by Power Marketing and that responsibility will continue to reside with Power Marketing after the Reorganization is complete. Power Marketing will ensure that power needed to serve the wires company's obligations is supplied through a combination of resources consisting of PWE-owned generation, APS-owned generation, and purchased power. Economic dispatch will be performed on the basis of availability and cost. System reliability operations will continue to be performed within the transmission organization as it always has been.

The proposed Reorganization involves the relocation of APS' ownership interest in its fossil generating facilities to PWE. This change in ownership is not expected to have a significant impact on PNW's use and enjoyment of the relocated assets. Power Marketing will conduct marketing efforts, both as a buyer and seller, for the PNW system. The Commission has recently recognized joint marketing efforts as a means to coordinate system operations within the meaning of the Act.[23] System dispatchers in Power Marketing will continually monitor the generation needs and capacity of the PNW system. Moreover, the generating assets will be dedicated to serving APS' bundled load and provider-of-last-resort obligations, albeit through a series of intra-holding company sales (that is, sales from PWE to Power Marketing and then to APS), at least through 2002. Beginning in 2003, APS will be required to procure at least 50% of its requirements through an open market bidding process. It is likely that PWE generation will be bid in to that requirement through PNW. To the extent non-PWE generation is selected to supply the APS bundled load and provider-of-last-resort obligations, that generation would be

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[23] American Electric Power Company, Inc., Holding Co. Act Release No. 27186 (June 14, 2000).

included in the purchased power portfolio of APS, and Power Marketing would simply include that purchased power in the generation dispatch queue, the same as it does for purchased power today. This method of operation will result in lower available energy costs for the APS distribution function.

In addition, PWE and APS will enter into interconnection agreements containing terms and conditions governing the interconnection of each of PWE's generators with the APS transmission/distribution system.[24] The agreements will include provisions for maintenance, operating and metering standards, access to facilities, redispatch, the provision of ancillary services, and liability issues. Power Marketing will also enter into transmission service agreements with APS under APS' FERC open access transmission tariff so that Power Marketing can receive deliveries from PWE and deliver electric energy to APS for service to APS' retail and wholesale native load customers.

Finally, the area of operations of the system will not be affected by the Reorganization and will continue to be primarily confined to a single area (e.g., APS' existing service territory in Arizona) that is not so large as to impair the advantages of continuing localized management, efficient operation, and effective regulation. See CP&L Energy, Inc., Holding Co. Act Release No. 27188 (June 15, 2000); Central Maine Power Company, et al., Holding Co. Act Release No. 26903 (Aug. 7, 1998).

3. Section 10(f)

Section 10(f) provides that "[t]he Commission shall not approve any acquisition . . . under this Section unless it appears to the satisfaction of the Commission that such State laws as

may apply in respect of such acquisition have been complied with, except where the Commission finds that compliance with such State laws would be detrimental to the carrying out of the provisions of Section 11 . . . ."

The Transfer Transaction is conditioned on full compliance with the laws of the Arizona. The Development Activities do not explicitly raise any questions of State law, other than siting and permitting issues; however, PNW fully complied with all applicable State laws when it initially formed PWE. APS is currently and will remain subject to the jurisdiction of the ACC with respect to the provision of retail electric service. APS and PNW have received the necessary approval from the ACC to proceed with the Transfer Transaction. A copy of this ACC approval is filed as Exhibit D-5 hereto.

For the reasons stated above, the proposed Reorganization meets the standards set forth in Sections 9(a)(2) and 10. The Reorganization involves the first step in the segregation of APS' existing utility assets and operations along functional lines into two companies – one company that is primarily in the wires business and a second in the generation business. The Reorganization will not unduly complicate the capital structure of the PNW system; nor will the Reorganization be detrimental to the public interest, the interests of investors or consumers, or the proper functioning of this system. Also, the Reorganization will yield significant benefits by allowing PNW's public-utility subsidiaries to more effectively compete in the electric utility industry. Therefore, the Commission should by order approve the Reorganization.

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[24] Interconnection agreements already exist for the generating units that are jointly owned or leased by APS; therefore, new interconnection agreements will be required only for those facilities that will be owned or leased in their entirety by PWE and for any new generating facilities developed or acquired by PWE.

B. PNW Will Continue to Claim a Section 3(a)(1) Exemption After the Reorganization.

Section 3(a)(1) of the Act makes an exemption from all of the provisions of the Act, except for Section 9(a)(2), available to a holding company, if "such holding company, and every subsidiary company thereof which is a public-utility company from which such holding company derives, directly or indirectly, any material part of its income, are predominately intrastate in character and carry on their business substantially in a single State in which such holding company and every such subsidiary company thereof are organized." After the Reorganization is complete, PNW and its two public-utility subsidiaries -- APS and PWE -- will be predominantly intrastate in character and will carry on their business substantially in Arizona, the state in which they are all organized.[25] In this regard, PNW will continue to claim an exemption pursuant to Section 3(a)(1) of the Act and Rule 2 of the Commission's regulations, by filing annual exemption statements on Form U-3A-2 following the Reorganization.

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[25] While APS' existing power marketing division was moved to PNW, and continues to perform its power marketing activities on a nationwide basis, PNW's utility operations are still predominately intrastate in character and conducted primarily in Arizona. As noted above, the Commission Staff has indicated in a series of no-action letters that power marketers are not considered "electric utility companies" under Section 2(a)(3) of the Act and, therefore, are not "public-utility companies" under Section 2(a)(5) of the Act. See, e.g., Sunoco Power Marketing, L.L.C., SEC No-Action Letter, 1997 SEC No-Act. LEXIS 785 (July 24, 1997); Enron Capital & Trade Resources Corp., SEC No-Action Letter, 1997 SEC No-Act. LEXIS 287 (Feb. 13, 1997).

ITEM 4 REGULATORY APPROVAL

The Transfer Transaction requires the approval of the ACC and FERC. APS has received an order approving the Transfer Transaction from the ACC, a copy of which is attached hereto as Exhibit D-5. APS also filed an application for approval of the proposed Transfer Transaction with the FERC, a copy of which is attached as Exhibit D-1. A copy of the final FERC order pursuant thereto was filed by amendment on December 8, 2000, as Exhibit D-2. Other than such enumerated approvals and the approval of the Commission hereunder, no other approvals are required for the Transfer Transaction and the movement of APS' fossil generating assets to PWE.[26] No approvals, other than the approval of the Commission under Section 9(a)(2) of the Act, are necessary in connection with PWE's Development Activities.[27]

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[26] As noted above, approval from the NRC will be obtained in connection with the relocation of APS' nuclear generating facilities to PWE. *See supra* n. 10.

[27] As noted above, PWE has filed with FERC an application for EWG status in connection with its Development Activities. In addition, although PWE's Development Activities may involve various siting, environmental, and other approvals, all of the approvals in connection with PWE's operation of West Phoenix No. 4 have already been obtained.

ITEM 5 PROCEDURE

PNW respectfully requests that there be no 30-day waiting period between the issuance of the Commission's order and the date on which it is to become effective. PNW also requests that there be no hearing on this application and that the Commission issue its order as soon as practicable after the filing hereof. PNW respectfully requests that the Commission issue and publish the requisite notice under Rule 23 with respect to the filing of this application not later than January 22, 2001, such notice to specify a date not later than February 22, 2001, by which comments may be entered and a date not later than May 1, 2001, as the date after which an order of the Commission granting and permitting this application to become effective may be entered by the Commission. A form of Notice is filed herewith as Exhibit H-1.

Without prejudice to its right to modify the same if a hearing should be ordered on this application, PNW hereby makes the following specifications required by paragraph (b) of Item 5 of Form U-1:

(1) There should not be a recommended decision by a hearing officer or any other responsible officer of the Commission.

(2) There should not be a 30-day waiting period between issuance of the Commission's order and the date on which the order is to become effective.

(3) PNW consents to the Division of Investment Management assisting in the preparation of the Commission's decision or order in this matter, unless such Division opposes this application.

ITEM 6 EXHIBITS AND FINANCIAL STATEMENTS

It is requested that the Commission send copies of all communications to PNW as follows:

Herbert I. Zinn
Pinnacle West Capital Corporation
400 North Fifth Street
Mail Station 8695
Phoenix, Arizona 85004

Mary Ann K. Huntington
Morgan, Lewis & Bockius LLP
1800 M Street, N.W.
Washington, D.C. 20036

A. **Exhibits**

Exhibit No.	Description of Document	Method of Filing
A-1	Restated Articles of Incorporation of PNW.	Incorporated by reference; File No. 1-8962, PNW Form 10-K for the year ended December 31, 1999.
A-2	Restated Articles of Incorporation of APS.	Incorporated by reference; File No. 1-4473, APS Form 8-K (Sept. 23, 1993).
A-3	Articles of Incorporation of PWE.	Filed herewith.
B-1	Form of Term Sheet.	Filed herewith.
D-1	Application of APS, PNW and PWE to FERC for Authorization to Transfer Jurisdictional Facilities.	Filed herewith.
D-2	Order of FERC.	Filed by amendment on December 8, 2000.
D-3	Retail Electric Competition Rules.	Incorporated by reference; file No. 1-4473, filed as Exhibit 10.2 to APS' Sept. 30, 1999

		Form 10-Q Report.
D-4	Comprehensive Settlement Agreement Related to the Implementation of Retail Electric Competition, filed with the Arizona Corporation Commission.	Filed by Amendment on April 27, 2001.
D-5	ACC Approval of the Settlement Agreement.	Filed by Amendment on April 27, 2001.
D-6	Amended Settlement Agreement.	Filed herewith.
D-7	ACC Order dated February 8, 2001 granting waiver for solar resources, and environmentally friendly renewable electricity technologies.	Filed by Amendment on April 27, 2001.
E-1	Map showing location of the generating facilities of APS that are being moved to PWE along with their related transmission facilities.	Filed herewith.
F-1	Signed initial opinion of counsel.	Filed by Amendment on April 27, 2001.
F-2	Past-tense opinion of counsel.	To be filed by amendment.
G-1	PNW, Form U-3A-2, "Statement by Holding Company Claiming Exemption under Rule U-2 from the Provisions of the Public Utility Holding Company Act of 1935."	Incorporated by reference; File No. 69-306, dated Feb. 29, 2000.

H-1	Form of Notice	Filed herewith.

B. Financial Statements

Statement No.	Description of Document	Method of Filing
FS-1	Historical consolidated financial statements of PNW	Incorporated by reference to Annual Reports on Form 10-K for the years ended 1999, 1998 and 1997
FS-2	Historical consolidated financial statements of APS	Incorporated by reference to Annual Reports on Form 10-K for the years ended 1999, 1998 and 1997

Although separate financial statements for PWE have not been included, PWE's financial information is included in the consolidated financial statements of PNW.

ITEM 7 INFORMATION AS TO ENVIRONMENTAL EFFECTS

None of the matters that are the subject of this application and declaration involves a "major federal action" nor do any of them "significantly affect the quality of the human environment" as those terms are used in Section 102(2)(C) of the National Environmental Policy Act. The transaction that is the subject of this application will not result in changes in the operation of the company that will have an impact on the environment. Neither APS nor PNW are aware of any federal agency that has prepared or is preparing an environmental impact statement with respect to the transactions that are the subject of this application.

SIGNATURE

Pursuant to the requirements of the Public Utility Holding Company Act of 1935, the undersigned company has duly caused this Application to be signed on its behalf by the undersigned thereunto duly authorized.

PINNACLE WEST CAPITAL CORPORATION

By: Barbara M. Gomez
Its: Treasurer

Date: April 27, 2001

Phoenix, Arizona

SETTLEMENT AGREEMENT

May 14, 1999

This settlement agreement ("Agreement") is entered into as of May 14, 1999, by Arizona Public Service Company ("APS" or the "Company") and the various signatories to this Agreement (collectively, the "Parties") for the purpose of establishing terms and conditions for the introduction of competition in generation and other competitive services that are just, reasonable and in the public interest.

INTRODUCTION

In Decision No. 59943, dated December 26, 1996, the Arizona Corporation Commission ("ACC" or the "Commission") established a "framework" for introduction of competitive electric services throughout the territories of public service corporations in Arizona in the rules adopted in A.A.C. R14-2-1601 *et seq.* (collectively, "Electric Competition Rules" as they may be amended from time to time). The Electric Competition Rules established by that order contemplated future changes to such rules and the possibility of waivers or amendments for particular companies under appropriate circumstances. Since their initial issuance, the Electric Competition Rules have been amended several times and are currently stayed pursuant to Decision No. 61311, dated January 5, 1999. During this time, APS, Commission Staff and other interested parties have participated in a number of proceedings, workshops, public comment sessions and individual negotiations in order to further refine and develop a restructured utility industry in Arizona that will provide meaningful customer choice in a manner that is just, reasonable and in the public interest.

This Agreement establishes the agreed upon transition for APS to a restructured entity and will provide customers with competitive choices for generation and certain other retail services. The Parties believe this Agreement will produce benefits for all customers through implementing customer choice and providing rate reductions so that the APS service territory may benefit from economic growth. The Parties also believe this Agreement will fairly treat APS and its shareholders by providing a reasonable opportunity to recover prudently incurred investments and costs, including stranded costs and regulatory assets.

Specifically, the Parties believe the Agreement is in the public interest for the following reasons. First, customers will receive substantial rate reductions. Second, competition will be promoted through the introduction of retail access faster than would have been possible without this Agreement and by the functional separation of APS' power production and delivery functions. Third, economic development and the environment will

benefit through guaranteed rate reductions and the continuation of renewable and energy efficiency programs. Fourth, universal service coverage will be maintained through APS' low income assistance programs and establishment of "provider of last resort" obligations on APS for customers who do not wish to participate in retail access. Fifth, APS will be able to recover its regulatory assets and stranded costs as provided for in this Agreement without the necessity of a general rate proceeding. Sixth, substantial litigation and associated costs will be avoided by amicably resolving a number of important and contentious issues that have already been raised in the courts and before the Commission. Absent approval by the Commission of the settlement reflected by this Agreement, APS would seek full stranded cost recovery and pursue other rate and competitive restructuring provisions different than provided for herein. The other Parties would challenge at least portions of APS' requested relief, including the recovery of all stranded costs. The resulting regulatory hearings and related court appeals would delay the start of competition and drain the resources of all Parties.

NOW, THEREFORE, APS and the Parties agree to the following provisions which they believe to be just, reasonable and in the public interest:

TERMS OF AGREEMENT

ARTICLE I
IMPLEMENTATION OF RETAIL ACCESS

1.1. The APS distribution system shall be open for retail access on July 1, 1999; provided, however, that such retail access to electric generation and other competitive electric services suppliers will be phased in for customers in APS' service territory in accordance with the proposed Electric Competition Rules, as and when such rules become effective, with an additional 140 MW being made available to eligible non-residential customers. The Parties shall urge the Commission to approve Electric Competition Rules, at least on an emergency basis, so that meaningful retail access can begin by July 1, 1999. Unless subject to judicial or regulatory restraint, APS shall open its distribution system to retail access for all customers on January 1, 2001.

1.2. APS will make retail access available to residential customers pursuant to its December 21, 1998, filing with the Commission.

1.3. The Parties acknowledge that APS' ability to offer retail access is contingent upon numerous conditions and circumstances, a number of which are not within the direct control of the Parties. Accordingly, the Parties agree that it may become necessary to modify the terms of retail access to account for such factors, and they further agree to address such matters in good faith and to cooperate in an effort to propose joint resolutions of any such matters.

1.4. APS agrees to the amendment and modification of its Certificate(s) of Convenience and Necessity to permit retail access consistent with the terms of this Agreement. The Commission order adopting this Agreement shall constitute the necessary Commission Order amending and modifying APS' CC&Ns to permit retail access consistent with the terms of this Agreement.

ARTICLE II
RATE MATTERS

2.1. The Company's unbundled rates and charges attached hereto as Exhibit A will be effective as of July 1, 1999. The Company's presently authorized rates and charges shall be deemed its standard offer ("Standard Offer") rates for purposes of this Agreement and the Electric Competition Rules. Bills for Standard Offer service shall indicate individual unbundled service components to the extent required by the Electric Competition Rules.

2.2. Future reductions of standard offer tariff rates of 1.5% for customers having loads of less than 3 MW shall be effective as of July 1, 1999, July 1, 2000, July 1, 2001, July 1, 2002, and July 1, 2003, upon the filing and Commission acceptance of revised tariff sheets reflecting such decreases. For customers having loads greater than 3 MW served on Rate Schedules E-34 and E-35, Standard Offer tariff rates will be reduced: 1.5%, effective July 1, 1999; 1.5% effective July 1, 2000; 1.25% effective July 1, 2001; and .75% effective July 1, 2002. The 1.5% Standard Offer rate reduction to be effective July 1, 1999, includes the rate reduction otherwise required by Decision No. 59601. Such decreases shall become effective by the filing with and acceptance by the Commission of revised tariff sheets reflecting each decrease.

2.3. Customers greater than 3 MW who choose a direct access supplier must give APS one year's advance notice before being eligible to return to Standard Offer service.

2.4. Unbundled rates shall be reduced in the amounts and at the dates set forth in Exhibit A attached hereto upon the filing and Commission acceptance of revised tariff sheets reflecting such decreases.

2.5. This Agreement shall not preclude APS from requesting, or the Commission from approving, changes to specific rate schedules or terms and conditions of service, or the approval of new rates or terms and conditions of service, that do not significantly affect the overall earnings of the Company or materially modify the tariffs or increase the rates approved in this Agreement. Nothing contained in this Agreement shall preclude APS from filing changes to its tariffs or terms and conditions of service which are not inconsistent with its obligations under this Agreement.

2.6. Notwithstanding the rate reduction provisions stated above, the Commission shall, prior to December 31, 2002, approve an adjustment clause or clauses which

will provide full and timely recovery beginning July 1, 2004, of the reasonable and prudent costs of the following:

(1) APS' "provider of last resort" and Standard Offer obligations for service after July 1, 2004, which costs shall be recovered only from Standard Offer and "provider of last resort" customers;

(2) Standard Offer service to customers who have left Standard Offer service or a special contract rate for a competitive generation supplier but who desire to return to Standard Offer service, which costs shall be recovered only from Standard Offer and "provider of last resort" customers;

(3) compliance with the Electric Competition Rules or Commission-ordered programs or directives related to the implementation of the Electric Competition Rules, as they may be amended from time to time, which costs shall be recovered from all customers receiving services from APS; and

(4) Commission-approved system benefit programs or levels not included in Standard Offer rates as of June 30, 1999, which costs shall be recovered from all customers receiving services from APS.

By June 1, 2002, APS shall file an application for an adjustment clause or clauses, together with a proposed plan of administration, and supporting testimony. The Commission shall thereafter issue a procedural order setting such adjustment clause application for hearing and including reasonable provisions for participation by other parties. The Commission order approving the adjustment clauses shall also establish reasonable procedures pursuant to which the Commission, Commission Staff and interested parties may review the costs to be recovered. By June 30, 2003, APS will file its request for the specific adjustment clause factors which shall, after hearing and Commission approval, become effective July 1, 2004. APS shall be allowed to defer costs covered by this Section 2.6 when incurred for later full recovery pursuant to such adjustment clause or clauses, including a reasonable return.

2.7. By June 30, 2003, APS shall file a general rate case with prefiled testimony and supporting schedules and exhibits; provided, however, that any rate changes resulting therefrom shall not become effective prior to July 1, 2004.

2.8. APS shall not be prevented from seeking a change in unbundled or Standard Offer rates prior to July 1, 2004, in the event of (a) conditions or circumstances which constitute an emergency, such as the inability to finance on reasonable terms, or (b) material changes in APS' cost of service for Commission regulated services resulting from federal, tribal,

state or local laws, regulatory requirements, judicial decision, actions or orders. Except for the changes otherwise specifically contemplated by this Agreement, unbundled and Standard Offer rates shall remain unchanged until at least July 1, 2004.

ARTICLE III
REGULATORY ASSETS AND STRANDED COSTS

3.1. APS currently recovers regulatory assets through July 1, 2004, pursuant to Commission Decision No. 59601 in accordance with the provisions of this Agreement.

3.2. APS has demonstrated that its allowable stranded costs after mitigation (which result from the impact of retail access), exclusive of regulatory assets, are at least $533 million net present value.

3.3. The Parties agree that APS should not be allowed to recover $183 million net present value of the amounts included above. APS shall have a reasonable opportunity to recover $350 million net present value through a competitive transition charge ("CTC") set forth in Exhibit A attached hereto. Such CTC shall remain in effect until December 31, 2004, at which time it will terminate. If by that date APS has recovered more or less than $350 million net present value, as calculated in accordance with Exhibit B attached hereto, then the nominal dollars associated with any excess recovery/under recovery shall be credited/debited against the costs subject to recovery under the adjustment clause set forth in Section 2.6(3).

3.4. The regulatory assets to be recovered under this Agreement, after giving effect to the adjustments set forth in Section 3.3, shall be amortized in accordance with Schedule C of Exhibit A attached hereto.

3.5. Neither the Parties nor the Commission shall take any action that would diminish the recovery of APS' stranded costs or regulatory assets provided for herein. The Company's willingness to enter into this Agreement is based upon the Commission's irrevocable promise to permit recovery of the Company's regulatory assets and stranded costs as provided herein. Such promise by the Commission shall survive the expiration of the Agreement and shall be specifically enforceable against this and any future Commission.

ARTICLE IV
CORPORATE STRUCTURE

4.1. The Commission will approve the formation of an affiliate or affiliates of APS to acquire at book value the competitive services assets as currently required by the Electric Competition Rules. In order to facilitate the separation of such assets efficiently and at the lowest possible cost, the Commission shall grant APS a two-year extension of time until

December 31, 2002, to accomplish such separation. A similar two-year extension shall be authorized for compliance with A.A.C. R14-2-1606(B).

4.2. Approval of this Agreement by the Commission shall be deemed to constitute all requisite Commission approvals for (1) the creation by APS or its parent of new corporate affiliates to provide competitive services including, but not limited to, generation sales and power marketing, and the transfer thereto of APS' generation assets and competitive services, and (2) the full and timely recovery through the adjustment clause referred to in Section 2.6 above for all of the reasonable and prudent costs so incurred in separating competitive generation assets and competitive services as required by proposed A.A.C. R14-2-1615, exclusive of the costs of transferring the APS power marketing function to an affiliate. The assets and services to be transferred shall include the items set forth on Exhibit C attached hereto. Such transfers may require various regulatory and third party approvals, consents or waivers from entities not subject to APS' control, including the FERC and the NRC. No Party to this Agreement (including the Commission) will oppose, or support opposition to, APS requests to obtain such approvals, consents or waivers.

4.3. Pursuant to A.R.S. § 40-202(L), the Commission's approval of this Agreement shall exempt any competitive service provided by APS or its affiliates from the application of various provisions of A.R.S. Title 40, including A.R.S. §§ 40-203, 40-204(A), 40-204(B), 40-248, 40-250, 40-251, 40-285, 40-301, 40-302, 40-303, 40-321, 40-322, 40-331, 40-332, 40-334, 40-365, 40-366, 40-367 and 40-401.

4.4. APS' subsidiaries and affiliates (including APS' parent) may take advantage of competitive business opportunities in both energy and non-energy related businesses by establishing such unregulated affiliates as they deem appropriate, which will be free to operate in such places as they may determine. The APS affiliate or affiliates acquiring APS' generating assets may be a participant in the energy supply market within and outside of Arizona. Approval of this Agreement by the Commission shall be deemed to include the following specific determinations required under Sections 32(c) and (k)(2) of the Public Utility Holding Company Act of 1935:

> APS or an affiliate is authorized to establish a subsidiary company, which will seek exempt wholesale generator ("EWG") status from the Federal Energy Regulatory Commission, for the purposes of acquiring and owning Generation Assets.
>
> The Commission has determined that allowing the Generation Assets to become "eligible facilities," within the meaning of Section 32 of the Public Utility Holding Company Act ("PUHCA"), and owned by an APS EWG affiliate (1) will benefit consumers, (2) is in the public interest, and (3) does not violate Arizona law.

The Commission has sufficient regulatory authority, resources and access to the books and records of APS and any relevant associate, affiliate, or subsidiary company to exercise its duties under Section 32(k) of PUHCA.

APS will purchase any electric energy from its EWG affiliate at market based rates. This Commission has determined that (1) the proposed transaction will benefit consumers and does not violate Arizona law; (2) the proposed transaction will not provide APS' EWG affiliate an unfair competitive advantage by virtue of its affiliation with APS; (3) the proposed transaction is in the public interest.

The APS affiliate or affiliates acquiring APS' generating assets will be subject to regulation by the Commission, to the extent otherwise permitted by law, to no greater manner or extent than that manner and extent of Commission regulation imposed upon other owners or operators of generating facilities.

4.5. The Commission's approval of this Agreement will constitute certain waivers to APS and its affiliates (including its parent) of the Commission's existing affiliate interest rules (A.A.C. R14-2-801, *et seq.*), and the rescission of all or portions of certain prior Commission decisions, all as set forth on Exhibit D attached hereto.

4.6. The Parties reserve their rights under Sections 205 and 206 of the Federal Power Act with respect to the rates of any APS affiliate formed under the provisions of this Article IV.

ARTICLE V
WITHDRAWAL OF LITIGATION

5.1. Upon receipt of a final order of the Commission approving this Agreement that is no longer subject to judicial review, APS and the Parties shall withdraw with prejudice all of their various court appeals of the Commission's competition orders.

ARTICLE VI
APPROVAL BY THE COMMISSION

6.1. This Agreement shall not become effective until the issuance of a final Commission order approving this Agreement without modification on or before August 1, 1999. In the event that the Commission fails to approve this Agreement without modification according to its terms on or before August 1, 1999, any Party to this Agreement may withdraw from this Agreement and shall thereafter not be bound by its provisions; provided, however, that if APS withdraws from this Agreement, the Agreement shall be null and void and of no further force and effect. In any event, the rate reduction provisions of this Agreement shall not take effect until this Agreement is approved. Parties so withdrawing shall be free to pursue

their respective positions without prejudice. Approval of this Agreement by the Commission shall make the Commission a Party to this Agreement and fully bound by its provisions.

6.2. The Parties agree that they shall make all reasonable and good faith efforts necessary to (1) obtain final approval of this Agreement by the Commission, and (2) ensure full implementation and enforcement of all the terms and conditions set forth in this Agreement. Neither the Parties nor the Commission shall take or propose any action which would be inconsistent with the provisions of this Agreement. All Parties shall actively defend this Agreement in the event of any challenge to its validity or implementation.

ARTICLE VII
MISCELLANEOUS MATTERS

7.1. To the extent any provision of this Agreement is inconsistent with any existing or future Commission order, rule or regulation or is inconsistent with the Electric Competition Rules as now existing or as may be amended in the future, the provisions of this Agreement shall control and the approval of this Agreement by the Commission shall be deemed to constitute a Commission-approved variation or exemption to any conflicting provision of the Electric Competition Rules.

7.2. The provisions of this Agreement shall be implemented and enforceable notwithstanding the pendency of a legal challenge to the Commission's approval of this Agreement, unless such implementation and enforcement is stayed or enjoined by a court having jurisdiction over the matter. If any portion of the Commission order approving this Agreement or any provision of this Agreement is declared by a court to be invalid or unlawful in any respect, then (1) APS shall have no further obligations or liability under this Agreement, including, but not limited to, any obligation to implement any future rate reductions under Article II not then in effect, and (2) the modifications to APS' certificates of convenience and necessity referred to in Section 1.4 shall be automatically revoked, in which event APS shall use its best efforts to continue to provide noncompetitive services (as defined in the proposed Electric Competition Rules) at then current rates with respect to customer contracts then in effect for competitive generation (for the remainder of their term) to the extent not prohibited by law and subject to applicable regulatory requirements.

7.3. The terms and provisions of this Agreement apply solely to and are binding only in the context of the purposes and results of this Agreement and none of the positions taken herein by any Party may be referred to, cited or relied upon by any other Party in any fashion as precedent or otherwise in any other proceeding before this Commission or any other regulatory agency or before any court of law for any purpose except in furtherance of the purposes and results of this Agreement.

7.4. This Agreement represents an attempt to compromise and settle disputed claims regarding the prospective just and reasonable rate levels, and the terms and conditions

of competitive retail access, for APS in a manner consistent with the public interest and applicable legal requirements. Nothing contained in this Agreement is an admission by APS that its current rate levels or rate design are unjust or unreasonable.

7.5. As part of this Agreement, APS commits that it will continue the APS Community Action Partnership (which includes weatherization, facility repair and replacement, bill assistance, health and safety programs and energy education) in an annual amount of at least $500,000 through July 1, 2004. Additionally, the Company will, subject to Commission approval, continue low income rates E-3 and E-4 under their current terms and conditions.

7.6. APS shall actively support the Arizona Independent Scheduling Administrator ("AISA") and the formation of the Desert Star Independent System Operator. APS agrees to modify its OATT to be consistent with any FERC approved AISA protocols. The Parties reserve their rights with respect to any AISA protocols, including the right to challenge or seek modifications to, or waivers from, such protocols. APS shall file changes to its existing OATT consistent with this section within ten (10) days of Commission approval of this Agreement pursuant to Section 6.1.

7.7. Within thirty (30) days of Commission approval of this Agreement pursuant to Section 6.1, APS shall serve on the Parties an Interim Code of Conduct to address inter-affiliate relationships involving APS as a utility distribution company. APS shall voluntarily comply with this Interim Code of Conduct until the Commission approves a code of conduct for APS in accordance with the Electric Competition Rules that is concurrently effective with codes of conduct for all other Affected Utilities (as defined in the Electric Competition Rules). APS shall meet and confer with the Parties prior to serving its Interim Code of Conduct.

7.8. In the event of any disagreement over the interpretation of this Agreement or the implementation of any of the provisions of this Agreement, the Parties shall promptly convene a conference and in good faith shall attempt to resolve such disagreement.

7.9. The obligations under this Agreement that apply for a specific term set forth herein shall expire automatically in accordance with the term specified and shall require no further action for their expiration.

7.10. The Parties agree and recommend that the Commission schedule public meetings and hearings for consideration of this Agreement. The filing of this Agreement with the Commission shall be deemed to be the filing of a formal request for the expeditious issuance of a procedural schedule that establishes such formal hearings and public meetings as may be necessary for the Commission to approve this Agreement in accordance with

Section 6.1 and that afford interested parties adequate opportunity to comment and be heard on the terms of this Agreement consistent with applicable legal requirements.

DATED at Phoenix, Arizona, as of this 14th day of May, 1999.

RESIDENTIAL UTILITY CONSUMER OFFICE

By Greg Patterson

Title Director

ARIZONA PUBLIC SERVICE COMPANY

By Jack Davis

Title President Delivery & Sales.

ARIZONA COMMUNITY ACTION ASSOCIATION

By Janet R. Regan

Title Executive Director

(Party) _____

By _____

Title _____

ARIZONANS FOR ELECTRIC CHOICE AND COMPETITION, a coalition of companies and associations in support of competition that includes Cable Systems International, BHP Copper, Motorola, Chemical Lime, Intel, [redacted], Honeywell, Allied Signal, Cyprus Climax Metals, Asarco, Phelps Dodge, [redacted], Homebuilders of Central Arizona, Arizona Mining Industry Gets Our Support, Arizona Food Marketing Alliance, Arizona Association of Industries, Arizona Multi-housing Association, Arizona Rock Products Association, Arizona Restaurant Association, [redacted], and Arizona Retailers Association. **

By Peter A. Woog

Title CHAIRMAN

(Party) _____

By _____

Title _____

(Party) _____

By _____

Title _____

* Enron is not a signatory to this Agreement

** Also included: Boeing, Az School Board Association, National Federation of Independent Business (NFIB), Az Hospital Association, Lockheed Martin, Abbot Labs,

Exhibit A
5/10/99
DA-R1

ELECTRIC DELIVERY RATES

ARIZONA PUBLIC SERVICE COMPANY
Phoenix, Arizona
Filed by: Alan Propper
Title: Director, Pricing and Regulation

A.C.C. No. XXXX
Tariff or Schedule No. DA-R1
Original Tariff
Effective: XXX XX, 1999

DIRECT ACCESS
RESIDENTIAL SERVICE

AVAILABILITY

This rate schedule is available in all certificated retail delivery service territory served by Company and where facilities of adequate capacity and the required phase and suitable voltage are adjacent to the premises served.

APPLICATION

This rate schedule is applicable to customers receiving electric energy on a direct access basis from any certificated Electric Service Provider (ESP) as defined in A.A.C. R14-2-1603. This rate schedule is applicable only to electric delivery required for residential purposes in individual private dwellings and in individually metered apartments when such service is supplied at one point of delivery and measured through one meter. For those dwellings and apartments where electric service has historically been measured through two meters, when one of the meters was installed pursuant to a water heating or space heating rate schedule no longer in effect, the electric service measured by such meters shall be combined for billing purposes.

This rate schedule shall become effective as defined in Company's Terms and Conditions for Direct Access (Schedule #10.)

TYPE OF SERVICE

Service shall be single phase, 60 Hertz, at one standard voltage (120/240 or 120/208 as may be selected by customer subject to availability at the customer's premise). Three phase service is furnished under the Company's Conditions Governing Extensions of Electric Distribution Lines and Services (Schedule #3). Transformation equipment is included in cost of extension. Three phase service is required for motors of an individual rated capacity of 7-1/2 HP or more.

METERING REQUIREMENTS

All customers shall comply with the terms and conditions for load profiling or hourly metering specified in Schedule #10.

MONTHLY BILL

The monthly bill shall be the greater of the amount computed under A. or B. below, including the applicable Adjustments.

A. RATE

May – October Billing Cycles (Summer):

	Basic Delivery Service	Distribution	System Benefits	Competitive Transition Charge
$/month	$10.00			
All kWh		$0.04158	$0.00115	$0.00930

November – April Billing Cycles (Winter):

	Basic Delivery Service	Distribution	System Benefits	Competitive Transition Charge
$/month	$10.00			
All kWh		$0.03518	$0.00115	$0.00930

B. MINIMUM $ 10.00 per month

(CONTINUED ON REVERSE SIDE)

ADJUSTMENTS

1. When Metering, Meter Reading or Consolidated Billing are provided by the Customer's ESP, the monthly bill will be credited as follows:

Meter	$1.30 per month
Meter Reading	$0.30 per month
Billing	$0.30 per month

2. The monthly bill is also subject to the applicable proportionate part of any taxes, or governmental impositions which are or may in the future be assessed on the basis of gross revenues of the Company and/or the price or revenue from the electric service sold and/or the volume of energy delivered or purchased for sale and/or sold hereunder.

SERVICES ACQUIRED FROM CERTIFICATED ELECTRIC SERVICE PROVIDERS

Customers served under this rate schedule are responsible for acquiring their own generation and any other required competitively supplied services from an ESP. The Company will provide and bill its transmission and ancillary services on rates approved by the Federal Energy Regulatory Commission to the Scheduling Coordinator who provides transmission service to the Customer's ESP. The Customer's ESP must submit a Direct Access Service Request pursuant to the terms and conditions in Schedule #10.

ON-SITE GENERATION TERMS AND CONDITIONS

Customers served under this rate schedule who have on-site generation connected to the Company's electrical delivery grid shall enter into an Agreement for Interconnection with the Company which shall establish all pertinent details related to interconnection and other required service standards. The Customer does not have the option to sell power and energy to the Company under this tariff.

TERMS AND CONDITIONS

This rate schedule is subject to the Company's Terms and Conditions for Standard Offer and Direct Access Services (Schedule #1) and Schedule #10. These schedules have provisions that may affect customer's monthly bill.

Exhibit A
5/10/99
DA-GS1

ELECTRIC DELIVERY RATES

ARIZONA PUBLIC SERVICE COMPANY
Phoenix, Arizona
Filed by: Alan Propper
Title: Director, Pricing and Regulation

A.C.C. No. XXXX
Tariff or Schedule No. DA-GS1
Original Tariff
Effective: XXX XX, 1999

DIRECT ACCESS
GENERAL SERVICE

AVAILABILITY

This rate schedule is available in all certificated retail delivery service territory served by Company at all points where facilities of adequate capacity and the required phase and suitable voltage are adjacent to the premises served.

APPLICATION

This rate schedule is applicable to customers receiving electric energy on a direct access basis from any certificated Electric Service Provider (ESP) as defined in A.A.C. R14-2-1603. This rate schedule is applicable to all electric service required when such service is supplied at one point of delivery and measured through one meter. For those customers whose electricity is delivered through more than one meter, service for each meter shall be computed separately under this rate unless conditions in accordance with the Company's Schedule #4 (Totalized Metering of Multiple Service Entrance Sections At a Single Premise for Standard Offer and Direct Access Service) are met. For those service locations where electric service has historically been measured through two meters, when one of the meters was installed pursuant to a water heating rate schedule no longer in effect, the electric service measured by such meters shall be combined for billing purposes.

This rate schedule shall become effective as defined in Company's Terms and Conditions for Direct Access (Schedule #10).

This rate schedule is not applicable to residential service, resale service or direct access service which qualifies for Rate Schedule DA-GS10.

TYPE OF SERVICE

Service shall be single or three phase, 60 Hertz, at one standard voltage as may be selected by customer subject to availability at the customer's premise. Three phase service is furnished under the Company's Conditions Governing Extensions of Electric Distribution Lines and Services (Schedule #3). Transformation equipment is included in cost of extension. Three phase service is not furnished for motors of an individual rated capacity of less than 7-1/2 HP, except for existing facilities or where total aggregate HP of all connected three phase motors exceed 12 HP. Three phase service is required for motors of an individual rated capacity of more than 7-1/2 HP.

METERING REQUIREMENTS

All customers shall comply with the terms and conditions for load profiling or hourly metering specified in the Company's Schedule #10.

MONTHLY BILL

The monthly bill shall be the greater of the amount computed under A. or B. below, including the applicable Adjustments.

A. RATE

June – October Billing Cycles (Summer):

	Basic Delivery Service	Distribution	System Benefits	Competitive Transition Charge
$ month	$12.50			
Per kW over 5		$0.721		
Per kWh for the first 2,500 kWh		$0.04255		
Per kWh for the next 100 kWh per kW over 5		$0.04255		
Per kWh for the next 42,000 kWh		$0.02901		
Per kWh for all additional kWh		$0.01811		
Per all kWh			$0.00115	
Per all kW				$2.43

(CONTINUED ON REVERSE SIDE)

A. RATE (continued)

November – May Billing Cycles (Winter):

	Basic Delivery Service	Distribution	System Benefits	Competitive Transition Charge
$/month	$12.50			
Per kW over 5		$0.652		
Per kWh for the first 2,500 kWh		$0.03827		
Per kWh for the next 100 kWh per kW over 5		$0.03827		
Per kWh for the next 42,000 kWh		$0.02600		
Per kWh for all additional kWh		$0.01614		
Per all kWh			$0.00115	
Per all kW				$2.43

PRIMARY AND TRANSMISSION LEVEL SERVICE:

1. For customers served at primary voltage (12.5kV to below 69kV), the Distribution charge will be discounted by 11.6%.
2. For customers served at transmission voltage (69kV or higher), the Distribution charge will be discounted 52.6%.
3. Pursuant to A.A.C. R14-2-1612.K.11, the Company shall retain ownership of Current Transformers (CT's) and Potential Transformers (PT's) for those customers taking service at voltage levels of more than 25kV. For customers whose metering services are provided by an ESP, a monthly facilities charge will be billed, in addition to all other applicable charges shown above, as determined in the service contract based upon the Company's cost of CT and PT ownership, maintenance and operation.

DETERMINATION OF KW

The kW used for billing purposes shall be the average kW supplied during the 15-minute period of maximum use during the month, as determined from readings of the delivery meter.

B. MINIMUM

$12.50 plus $1.74 for each kW in excess of five of either the highest kW established during the 12 months ending with the current month or the minimum kW specified in the agreement for service, whichever is the greater.

ADJUSTMENTS

1. When Metering, Meter Reading or Consolidated Billing are provided by the Customer's ESP, the monthly bill will be credited as follows:

Meter	$4.00 per month
Meter Reading	$0.30 per month
Billing	$0.30 per month

2. The monthly bill is also subject to the applicable proportionate part of any taxes, or governmental impositions which are or may in the future be assessed on the basis of gross revenues of the Company and/or the price or revenue from the electric service sold and/or the volume of energy delivered or purchased for sale and/or sold hereunder.

SERVICES ACQUIRED FROM CERTIFICATED ELECTRIC SERVICE PROVIDERS

Customers served under this rate schedule are responsible for acquiring their own generation and any other required competitively supplied services from an ESP or under the Company's Open Access Transmission Tariff. The Company will provide and bill its transmission and ancillary services on rates approved by the Federal Energy Regulatory Commission to the Scheduling Coordinator who provides transmission service to the Customer's ESP. The Customer's ESP must submit a Direct Access Service Request pursuant to the terms and conditions in Schedule #10.

(CONTINUED ON PAGE 3)