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BEFORE THE ARIZONA CORPORATION COMMISSION

WILLIAM A. MUNDELL
Chairman
JIM IRVIN
Commissioner
MARC SPITZER
Commissioner

IN THE MATTER OF THE GENERIC PROCEEDINGS CONCERNING ELECTRIC RESTRUCTURING	DOCKET NO. E-00000A-02-0051
IN THE MATTER OF ARIZONA PUBLIC SERVICE COMPANY'S REQUEST FOR VARIANCE OF CERTAIN REQUIREMENTS OF A.A.C. 4-14-2-1606	DOCKET NO. E-01345A-01-0822
IN THE MATTER OF THE GENERIC PROCEEDINGS CONCERNING THE ARIZONA INDEPENDENT SCHEDULING ADMINISTRATOR	DOCKET NO. E-00000A-01-0630
IN THE MATTER OF TUCSON ELECTRIC COMPANY'S APPLICATION FOR A VARIANCE OF CERTAIN ELECTRIC POWER COMPETITION RULES COMPLIANCE DATES	DOCKET NO. E-01933A-98-0471
ISSUES IN THE MATTER OF TUCSON ELECTRIC POWER COMPANY'S APPLICATION FOR A VARIANCE OF CERTAIN ELECTRIC COMPETITION RULES COMPLIANCE DATES	DOCKET NO. E-01933A-02-0069 **NOTICE OF FILING DIRECT TESTIMONY**

Arizona Corporation Commission
DOCKETED
MAR 29 2002
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DIRECT TESTIMONY OF MICHAEL R. SCHUYLER

ON BEHALF OF
PANDA GILA RIVER, L.P.

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I. QUALIFICATIONS

Q. PLEASE STATE YOUR NAME, POSITION AND BUSINESS ADDRESS.

A. My name is Michael R. Schuyler. I am currently senior vice president of Energy Marketing and Development for TECO Power Services Corporation ("TPS"). My business address is 702 North Franklin Street, Tampa, FL 33602.

Q. PLEASE SUMMARIZE YOUR EDUCATIONAL BACKGROUND.

A. I received a Bachelor of Science degree in Engineering and a Master of Science degree in Engineering Management, both from the University of South Florida. I am a Registered Professional Engineer in the State of Florida, and a senior member of the Institute of Industrial Engineers.

Q. PLEASE SUMMARIZE YOUR PROFESSIONAL EXPERIENCE.

A. From 1981 to 1989, I was employed by Tampa Electric Company in varying positions of increasing responsibility. From 1997 to 1998, I was Director of Gas Supply and Regulatory Affairs at Peoples Gas Company, a TECO Energy subsidiary and Florida's leading provider of natural gas, where I was in charge of gas supply and regulatory affairs activities. I joined TPS at its inception in 1989, and have had responsibility for project analysis, fuel management, environmental and regulatory affairs, as well as power sales contracting and marketing. I was named Vice President-Marketing and Development for TPS in 1998, and Senior Vice President in December 2000.

II. PURPOSE AND SUMMARY OF TESTIMONY

Q. ON WHOSE BEHALF ARE YOU PRESENTING THIS TESTIMONY?

A. I am testifying on behalf of Panda Gila River, L.P. ("Panda")

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. The purpose of my testimony is to explain Panda's corporate structure, describe the generation facility (the "Project") Panda is constructing in Arizona, describe Panda's intention to sell power at wholesale in the competitive Arizona market and provide the basic terms and conditions under which Panda would be willing to sell power to Arizona Public Service Company ("APS") to satisfy APS's Standard Offer Service requirements pursuant to Rule 1606 of the Arizona Corporation Commission's Electric Competition Rules, A.A.C. 14-2-1606.

Q. PLEASE SUMMARIZE YOUR TESTIMONY.

A. Panda stands ready to sell to APS output from the Project to satisfy a significant portion of APS's Standard Offer Service requirements at rates and on terms and conditions that are superior to the proposed Power Purchase Agreement ("PPA") between APS and Pinnacle West Capital Corporation ("PWCC") at issue in this proceeding. Given the opportunity, Panda is prepared to submit a firm offer to APS in response to a Request for Proposal ("RFP"), or as part of bilateral contract negotiations, that provides substantial benefit to APS's ratepayers not provided under the PPA.

III. <u>DESCRIPTION OF PANDA AND THE PROJECT</u>

Q. PLEASE DESCRIBE PANDA'S STRUCTURE AND ORGANIZATION.

A. Panda is structured as a limited partnership. The limited partner is Panda Gila River II, LLC, and the general partner is Panda Gila River I, LLC. Each of these is wholly-owned by TECO-PANDA Generating Company, L.P. ("TPGC"). TPGC has two general partners, TPS GP, Inc. and Panda GS I, Inc., and two limited partners, TPS LP, Inc. and Panda GS II, Inc. Each of the general partners has equal representation on the Project Management Committee, which makes all managerial decisions for the Project. TPS GP, Inc. and TPS LP, Inc. are wholly-owned subsidiaries of TPS. Panda GS I, LLC and Panda GS II, LLC are wholly-owned subsidiaries of PLC II, LLC. PLC II, LLC is in turn a wholly-owned subsidiary of Panda Energy International, Inc. ("PEI"). In addition to the Gila River facility, TPGC is also constructing a 2,200 MW facility located near El Dorado, Arkansas.

Q. PLEASE DESCRIBE TPS.

A. TPS develops, owns and operates electricity generation projects in North America. TPS has economic interests in excess of 10,000 MW of announced or operating generating projects, with a net ownership totaling nearly 7,000 MW. Domestically, TPS has announced projects to serve customers in 18 states, spanning the southern half of the United States. TPS owns or is constructing generation facilities in Arizona, Texas, Louisiana, Mississippi, Arkansas, Florida, Virginia and Hawaii. In addition, TPS owns facilities outside the U.S. in Guatemala and the Czech Republic.

Q. PLEASE DESCRIBE PEI.

A. PEI is a privately held, non-regulated electric generation company whose primary focus is the development, ownership and operation of state-of-the-art, environmentally clean, low-cost power plants. PEI owns and operates plants in North Carolina, Maryland and Nepal, and has an ownership interest in four facilities in Texas and Oklahoma. PEI has developed 9,000 MW that are either under construction or in commercial operation, and has 10,000 MW of capacity currently in advanced stages of development, for which construction has not commenced.

Q. PLEASE DESCRIBE THE PROJECT.

A. Panda's Arizona facility will be a state-of-the-art gas-fired, combined cycle generating facility with a nominal capacity of 2,300 megawatts. The Project will consist of four units, each with a nominal capacity of 575 MW. The Project is configured with eight GE combustion turbines, eight heat recovery steam generators with selective catalytic reduction for lowering NOx emissions, and four single-flow, axial exhaust condensing steam turbines, in four two-on-one power blocks. The Project is expected to cost approximately $ 1.4 billion.

Q. WHERE WILL THE PROJECT BE LOCATED?

A. The Project is physically located in the Town of Gila Bend, Arizona, approximately sixty miles southwest of Phoenix.

Q. HOW WILL THE PROJECT BE INTERCONNECTED WITH THE APS TRANSMISSION AND DISTRIBUTION SYSTEM?

A. The Project will be interconnected to the APS grid at the newly-constructed Jojoba Substation. The Jojoba Substation will be interconnected with the Palo Verde – Kyrene transmission line jointly owned by APS, the Salt River Project ("SRP"), Public Service Company of New Mexico and El Paso Electric Company. The interconnection agreement was accepted for filing, with an effective date of February 20, 2001, by the Federal Energy Regulatory Commission ("FERC") in a letter order issued on February 28, 2001 in Docket Nos. ER01-770-000 and ER01-917-000. Necessary amendments to the documents governing ownership and operation of the Kyrene line were filed with the FERC on December 21, 2001, and accepted for filing by the FERC on March 27, 2002. There is also a 230 kV interconnection on the Gila Bend – Liberty 230 kV transmission line. APS recognized this alternate interconnection in its Facilities Study dated April 2000.

Q. WHEN WILL THE PROJECT BE COMMERCIALLY OPERATIONAL?

A. The Project is being constructed in four phases. The first phase is expected to be commercially operational in March 2003, with the facility being fully operational in August 2003. As of the end of 2001, construction of the Project was ten percent complete, but significant pre-construction work is not reflected in this figure. As a more representative measure, Panda had spent approximately forty percent of the Project's anticipated construction costs as of the end of 2001.

Q. IF THE PROJECT WILL NOT BE FULLY OPERATIONAL UNTIL MID-2003, HOW DOES PANDA PROPOSE TO SUPPLY POWER FOR APS'S STANDARD OFFER SERVICE REQUIREMENTS BEGINNING IN 2003?

A. As I discuss in this testimony, and as Panda witness Dr. Roach discusses in his direct testimony, a competitive PPA provides significant benefits over the proposed PPA. Consequently, the Commission should require APS and PWCC to make reasonable accommodations for facilities coming online later in 2003, rather than lock ratepayers into an unreasonable, 30-year affiliate contract. This is especially true in Arizona, where peak electric usage occurs in the summer, by which time Panda's facility will be largely operational.

IV. <u>RELIANCE ON RULE 1606</u>

Q. DID PANDA RELY ON RULE 1606(B) IN DECIDING TO PLAN, CONSTRUCT AND OPERATE ITS ARIZONA GENERATION FACILITY?

A. Not exclusively, no. It would not have been sound business judgment to commit over a billion dollars to a project without considering all available markets for the plant's output. Nevertheless, it was abundantly clear at the time the Project was announced in 2000 and at the time of the Project's financial closing in July 2001 that Arizona was committed to the development of a robust, competitive wholesale market for electricity, and that the Project would be able to compete for a share of APS's Standard Offer Service requirements under the RFP required by Rule 1606(B).

Q. IF THE COMMISSION APPROVES THE VARIANCE REQUEST AND THE PPA, COULDN'T PANDA SIMPLY SELL POWER INTO CALIFORNIA OR ANOTHER WESTERN MARKET?

A. It is possible that Panda could find a market for some of the Project's output, but markets in the West provide an inadequate remedy if APS succeeds in foreclosing wholesale competition for its Standard Offer Service requirements. California entered into long-term contracts for a substantial portion of its power requirements, and there is no reason to believe that the hydrological conditions leading to reduced hydropower output during the last couple of years in the Pacific Northwest will continue indefinitely. Therefore, if Panda is not permitted to fairly compete in the Arizona wholesale market, its ability to sell wholesale power produced by the Project will be significantly impaired and could jeopardize a nearly one-and-a-half billion dollar investment. I would assume other competitive suppliers would be affected similarly, and would be forced to rethink their commitment to existing and/or future investments in Arizona. Several competitive suppliers have invested or have committed to invest billions of dollars in Arizona, investment that would be seriously imperiled, like Panda, if APS is permitted to crush a nascent competitive market, even before the market's start date.

Q. COULDN'T PANDA SELL POWER TO APS UNDER THE COMPETITIVE BIDDING PROVISIONS PROPOSED IN THE PPA?

A. Perhaps, but allowing Panda to compete for a small fraction of APS's Standard Offer Service requirements in 2003, with the amount competitively bid not increasing to even one-quarter of APS's Standard Offer Service requirements until

2008 (five years after the Project is commercially operational) is completely inadequate, clearly suboptimal for Arizona's ratepayers, and would do far too little, far too late to permit further development of a competitive wholesale market in Arizona.

V. <u>TRANSMISSION AND FUEL AVAILABILITY</u>

Q. HOW WILL PANDA OBTAIN FUEL TO OPERATE THE PROJECT?

A. As I mentioned earlier, the Project will be gas-fired. Through capacity release on the SoCal Natural Gas system and capacity purchases on the El Paso Natural Gas ("EPNG") system, Panda has secured firm natural gas supply and transportation for approximately 45% of the Project's Maximum Daily Quantity ("MDQ") and 71% of the Project's projected Average Daily Quantity of gas use. Securing more than half of the needed fuel supply and transportation in advance of commercial operation would not have made sense from a business standpoint. In any event, Panda could always enter into tolling contracts where the purchaser is responsible for supplying fuel necessary to produce power supplied under the contract.

Q. IF APS AWARDED A CONTRACT TO PANDA UNDER RULE 1606(B), WOULD PANDA HAVE NECESSARY GAS SUPPLIES TO OPERATE THE PROJECT?

A. Yes. Panda is confident that it will be able to enter into firm supply and transportation contracts for the full output of the plant if it proves necessary. The Project has minimized risk associated with single pipeline access by establishing multiple hot taps into separate loops of EPNG's southern mainline and devising a diverse natural gas supply and transportation portfolio to receive gas supplies from the San Juan, Permian, and Anadarko Basins. While some commentators have expressed concerns with pipeline availability, Panda does not believe gas supply is an issue. Numerous firm transportation options are available to Panda, including:

- EPNG proposes to construct an additional 700,000 MMBtu/day firm transportation capacity in California, with a backhaul (displacement) from interconnects with Kern River, SoCal, Mojave, Transwestern Pipeline ("TW") and others going east (all of which would be available to Panda);
- Panda is in negotiations with TW for interconnect with TW's "Sun Devil" expansion in 2004. The Sun Devil interconnect will be capable of 750,000 MMBtu/day. Panda has proposed 150,000 MMBtu/day firm transportation from TW's San Juan supply basin, but can ask for more capacity;
- In response to a recent request from Panda for available firm supply and transportation, suppliers and marketers indicated availability of 3 Bcf/day of firm supply, and firm transportation of more than 900,000 MMBtu/day on EPNG and 600,000 MMBtu/day on TW; and
- A number of entities, including Pinnacle West, have expressed intentions to pursue gas storage in the Southwest, which will facilitate securing fuel supply.

If anything, it is APS and PWCC, not Panda, that is at risk for inadequate fuel supply for its gas-fired facilities. A number of proceedings are ongoing at the FERC to address capacity issues on the EPNG system, including APS's attempts to assign capacity to its affiliate, PWEC, for the Redhawk facility. The FERC Staff recently concluded that, due in part to attempts by customers like APS to manipulate capacity on the system, EPNG's full requirements contracts have become unjust and unreasonable. Consequently, the FERC Staff recommended that full requirements customers, like APS, be required to convert to contract demand service. Under the FERC Staff proposal, the MDQ under such contract would be the greater of their coincidental peak day usage as of December 12, 2001, or their 1996 Billing Determinant ("BD") settlement volume. Because Redhawk was not in operation as of December 12, 2001, and APS has grown since 1996, it is questionable, at best, whether APS would have enough BD capacity to include PWEC in any successor EPNG contract for the Redhawk plant.

In any case, Panda would expect that a purchaser of power from the Project would require Panda to have firm gas supply, and would require Panda to adequately demonstrate such gas supply before accepting a bid or entering into a bilateral contract. Panda anticipates that it would have no problem satisfying such a requirement.

Q. DOES PANDA HAVE TRANSMISSION CONTRACTS FOR DELIVERY OF THE OUTPUT OF THE PROJECT?

A. Currently, Panda has secured 333 MW of firm transmission capacity to Palo Verde from APS pursuant to the APS Open Access Transmission Tariff. It is Panda's understanding that significant additional capacity is available on the Kyrene to Palo Verde line through SRP, one of the owners of the line. Once a generator is at Palo Verde, there is no distinction between a merchant generator and APS's Redhawk facility. In addition, Panda's interconnection agreement with APS allows Panda to inject power into the APS system at Jojoba. As part of Panda's interconnection agreement, Panda paid fees and upgrades costing about $67 million. Moreover, if the Panda facility were designated as a network resource, the Project could substitute for existing network resources (like APS's own generation), using transmission capacity freed up when the previous network resources are no longer used to serve APS's Standard Offer Service requirements.

VI. PROJECT RELIABILITY

Q. APS WITNESS JACK DAVIS STATES (P. 20) THAT COMBINED-CYCLE PLANTS "HAVE YET TO BE TESTED FOR LONG PERIODS OF TIME COMPARABLE TO THE EXPERIENCE OF MOST OF THE DEDICATED UNITS." APS WITNESS JOHN LANDON STATES (P. 12) THAT "MANY NEWLY CONSTRUCTED COMBINED CYCLE UNITS HAVE PERFORMED LESS WELL THAN EXPECTED." DO YOU AGREE?

A. Absolutely not. I am aware of no evidence to support the contention that combined-cycle facilities have performed at anything less than the level of performance expected of state-of-the-art technology. Both of the TPGC facilities will be combined-cycle units, and the independent projects under construction by TPS in Mississippi and Arkansas are gas-fired, combined-cycle units. Two of TPS's operational generation facilities are gas-fired combined-cycle units – the Hardee Power Station and the Frontera Power Station. PWEC apparently agrees that combined cycle technology is reliable, and is installing gas-fired combined cycle units at Redhawk and West Phoenix. If there were any evidence that combined-cycle performance was questionable, TPS and Panda, who have invested billions of dollars in combined-cycle facilities, would not use the technology so extensively. Any risk of poor performance in a competitive, long-term power supply agreement would be borne by Panda, not by the APS ratepayers, unlike the APS PPA, which passes through all costs to the customers. Panda witness Dr. Roach describes this extensively in his testimony.

VII. <u>PANDA'S WILLINGNESS TO SUPPLY POWER TO APS FOR APS'S STANDARD OFFER SERVICE REQUIREMENTS</u>

Q. IF THE REQUEST FOR A VARIANCE IS REJECTED, WILL PANDA OFFER TO SUPPLY POWER FOR APS'S STANDARD OFFER SERVICE REQUIREMENTS?

A. Yes. In fact, in a Request for Order to Show Cause filed in this proceeding on March 20, 2002, Panda requested that the Commission require APS to immediately issue an RFP, as the RFP would prove that numerous competitive suppliers would be interested in submitting bona fide offers. Panda, given the opportunity, would definitely submit an offer in an RFP or negotiate terms of an arms-length bilateral contract with APS.

Q. IN ITS VARIANCE REQUEST, APS STATES THAT THE PROPOSED PPA PROVIDES A COMBINATION OF RELIABILITY, FLEXIBILITY AND PRICE THAT IS NOT AVAILABLE FROM THE WHOLESALE MARKET. DO YOU AGREE?

A. No, I do not agree. It is difficult, obviously, to answer this question with absolute clarity, because APS has refused to issue an RFP or enter into public negotiations for an arms-length contract with any entity other than its affiliate, PWCC. Either of these options for securing power from the market would provide Panda and other competitive suppliers with certainty regarding APS's power requirements and would therefore drive the development of any offer. Nevertheless, Panda anticipates that, upon execution of an appropriate confidentiality agreement with APS, it would make a firm offer to APS to sell up to 2,000 MW of capacity and associated energy in a contract with equivalent or superior reliability and performance guarantees than are contained in the PPA. Panda has long been interested in entering into a long-term contract with APS.

Panda witness Dr. Roach discusses in his direct testimony the types of contract terms he expects to see in a competitive PPA. Panda anticipates that the offer it would make to APS would be similar to the contracts he describes. The structure and terms of such arrangement could include any of the following, as negotiated by the parties, each of which is superior to the PPA:

- Greater flexibility than provided under the PPA, including take-or-pay service with some fixed energy components and additional capacity that provides APS with full dispatchability, under fuel terms tied to transparent price indices;
- Fuel prices set to a published index, with the Project taking the risk for abnormal transportation or deliverability costs;
- Fixed capacity charges covering the Project's capital costs or fixed formula rates with published escalation indices for capacity charges;
- Commitment to operate the Project within required performance parameters, at efficiencies significantly better than are provided under the PPA; and

- Reduction of capacity payments or liquidated damages for failure to meet performance parameters or failure to maintain minimum required unit availability.

Q. APS WITNESS DAVIS ARGUES THAT COMPETITIVE SUPPLIERS ARE LESS RELIABLE BECAUSE THEY DON'T HAVE THE "FUEL DIVERSITY" THAT THE DEDICATED UNITS DERIVE FROM A PORTFOLIO OF GENERATION UNITS, INCLUDING COAL, GAS AND NUCLEAR UNITS. DO YOU AGREE?

A. No, for several reasons. First, absolutely nothing in the Electric Competition Rules prevents APS from assembling a diverse portfolio of competitive resources. In an independently administered RFP, PWEC could submit bids on behalf of each of the Dedicated Units. To the extent that the Commission requires a mix of fuel sources, the third party administering the RFP could accept bids from some of the coal and nuclear Dedicated Units, along with gas-fired units like Panda's Project. This would result in absolutely the same reliability advantage that APS claims is present in its proposed Affiliate PPA, while also promoting a competitive wholesale market, with the associated price and efficiency benefits.

Also, any argument about the fuel diversity of the proposed PPA must recognize that a significant portion of PWEC's own generation is gas-fired. APS recognizes in the PPA that at least some of the Dedicated Units will be retired during the likely 30-year term of the PPA (to be replaced by Supplemental or Replacement Energy Products). As the Dedicated Units are retired, it is likely that they will be replaced by the most efficient facilities possible, which are likely to be gas-fired.

Q. WHAT PERFORMANCE AND RELIABILITY GUARANTEES WOULD PANDA OFFER APS?

A. As discussed above, Panda would commit to operate its facility within required performance parameters, would commit to supply APS with designated capacity and associated energy, and would commit to designated unit availability. Each of these commitments is at least as good as, if not better than, those provided in the PPA. As Panda witness Dr. Roach explains, the APS-PWCC PPA places all price risks on the Standard Offer Service ratepayer, exposes risk averse ratepayers to risk of future increased environmental costs, and provides no real and enforceable performance or reliability guarantees.

Q. WHAT OTHER TERMS AND CONDITIONS WOULD BE INCLUDED IN A PANDA PPA?

A. Panda would not demand the non-competitive terms present in the APS PPA. Dr. Roach explains why the PPA is not competitive when compared to the California DWR contracts APS uses as benchmarks and why the PPA is inferior to the sorts of contracts competitive suppliers are willing to sign. Panda would, for example, expect that its PPA would be for a shorter and more reasonable time period (to allow customers to benefit from changes in the marketplace) and would contain more reasonable default, remedy and *force majeure* provisions. The APS PPA contains no real penalty for non-performance, and allows either party an essentially unlimited right to claim it should be excused from non-performance due to unanticipated events. Panda expects that a competitive power supply contract negotiated at arms-length would only excuse non-performance in the case of uncontrollable factors such as Acts of God.

Q. DO YOU BELIEVE, THEN, THAT PANDA CAN OFFER APS'S RATEPAYERS AN OFFER THAT IS BETTER THAN THE PROPOSED PPA?

A. Yes, definitely. As discussed above, the proposed PPA provides no real protection to APS's ratepayers against rising costs and non-performance. Panda would offer an enforceable agreement at competitive prices that transfers risk to Panda and away from the most risk averse ratepayers. Furthermore, this offer would be backed by a new, state-of-the-art, highly efficient generation facility constructed, owned and operated by entities with a track record of performance. Allowing APS to lock up its Standard Offer Service requirements in a self-serving, thirty-year contract, on the other hand, would significantly harm the nascent Arizona competitive wholesale market while imposing unnecessary costs and risk on the ratepayers.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes.

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BEFORE THE ARIZONA CORPORATION COMMISSION

WILLIAM A. MUNDELL
CHAIRMAN
JIM IRVIN
COMMISSIONER
MARC SPITZER
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TESTIMONY OF
CRAIG R. ROACH, Ph.D.

ON BEHALF OF
PANDA GILA RIVER, L.P.

MARCH 29, 2002

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I. QUALIFICATIONS

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

A. My name is Craig R. Roach. I am a Principal with Boston Pacific Company, Inc. My business address is 1100 New York Avenue, NW, Suite 490 East, Washington, DC 20005.

Q. Please summarize your educational background.

A. I earned my Ph.D. in Economics from the University of Wisconsin and my Bachelor of Science Degree in Economics, *cum laude*, from John Carroll University.

Q. Please summarize your professional experience.

A. I have twenty-six years of experience working on investments in, policies for, and litigation concerning the electricity and natural gas businesses. From 1975 to 1979, I was an economist with the U.S. Congressional Budget Office. From 1979 to 1982, I was a Project Manager with ICF Incorporated, an energy and environmental consulting firm.

From 1983 to the present, I have worked with Boston Pacific, first in San Francisco and since 1987 in Washington, D.C. Boston Pacific is an energy consulting and investment services firm. My clients include competitive power suppliers, electric utilities, electric and gas marketers, gas pipeline companies, trade associations, government agencies, and energy consumers.

Q. Do you have experience as an expert witness?

A. Yes. I have extensive experience as an expert witness on electricity and natural gas issues. A complete list of my testimony is contained in Exhibit No.__ (CRR-1). Also shown therein is a list of my speeches and articles on issues in the electricity and natural gas businesses.

I have submitted testimony, affidavits, or comments to the Federal Energy Regulatory Commission in sixteen proceedings, to public utility commissions in fourteen states (some on multiple occasions), in arbitrations, in State Court, in Federal Court, to a City Council, before two Canadian Provincial Boards, and before a Congressional Subcommittee.

Q. Do you have relevant experience beyond that reflected in your expert testimony?

A. Yes. Beyond expert testimony, I have extensive experience providing financial advisory services for power project development and asset acquisition throughout the U.S. and around the world.

II. PURPOSE AND SUMMARY OF TESTIMONY

Q. On whose behalf are you presenting this testimony?

A. I am presenting this Testimony on behalf of Panda Gila River, L.P. ("Panda").

Q. What is your relationship to Panda?

A. I am an independent consultant retained by Counsel for Panda. The views expressed herein are my own and may not reflect those of Panda in all respects.

Q. What is the purpose of your Testimony?

A. The purpose of my Testimony is to respond to the arguments used by Arizona Public Service Company ("APS") in support of its request that the Arizona Corporation Commission (the "Commission"): (a) grant it a waiver of ("variance" from) the Electric Competition Rules, which require APS to competitively procure all of the power it uses to serve Standard Offer customers starting in January 2003; and (b) find that the long-term (29-year) Power Purchase Agreement (the "APS Affiliate PPA") proposed by APS with Pinnacle West Capital Corporation (PWCC), an APS affiliate, is just and reasonable.

Q. Would you please summarize the APS arguments?

A. Yes. The essence of the APS arguments can be summarized in four points: (a) granting the variance is not contrary to the letter or spirit of the Commission's Electric Competition Rules; (b) not granting the variance will lead to "dire consequences" in terms of price instability and unreliable power supply in Arizona; (c) granting the variance will do no harm to competition, and indeed will make no difference in market prices; and (d) the APS Affiliate PPA offers a superior deal in terms of price and reliability that is unobtainable in the competitive market.

Q. What is your response to the first APS argument?

A. My response is that granting a variance would be wholly contrary to the letter and spirit of the Electric Competition Rules (the "Rules").

The letter of the Rules requires that a variance may be granted only if it is in the public interest. The public interest would be served if, and only if, APS provides proof that the APS Affiliate PPA is superior to all offers obtainable from the competitive market. It is clear that APS could offer such proof if, and only if, it had actually solicited and evaluated such offers. That is, APS' claim of acting in the public interest could be supported if, and only if, it had complied in the first place with the Commission's requirement for competitive procurement. Instead, APS is here asking the Commission to waive that requirement.

Since 1996, the Commission has made it clear that it intends to make the transition to a competitive generation market. Its requirement to use competitive procurement for Standard Offer service was made clear four years ago in 1998. Yet, APS is here at the eleventh hour to ask for another delay in complying with the Rules. All the while, APS was investing $1 billion in new generation that it now asks to be included in the APS Affiliate PPA. There is no reason for the Commission to retreat, as APS is now asking it to do, from its goal of gaining the benefits of competition for the people of Arizona.

Q. What is your response to the second APS argument?

A. My response is that APS provides no evidence of "dire consequences" if the variance is not granted. APS says there is no time for competitive procurement. But APS has not even attempted to obtain bids or enter into bilateral contracts, and provides no evidence that competitors would not be willing to submit competitive bids or negotiate bilateral contracts. Even if sufficient competitive generation is not available precisely on January 1, 2003, APS could address such problems without taking Standard Offer service requirements out of the market for as long as twenty-nine years.

The use of requests for proposals ("RFP") is common practice for regulators seeking a market test for new utility power supplies. With no time pressure, 180 days is ample time to conduct an RFP. When time is tight, the Virginia Commission has shown an RFP can be completed successfully in just 78 days, despite the local utility's claim that there was insufficient time.

Clearly, it is overkill to ask for a 29-year variance as APS has done. Indeed, if APS is concerned about possible delays, it should worry more about delays caused by seeking FERC approval later this year for its Affiliate PPA without appropriate benchmark evidence or conducting an RFP.

Q. Does APS make claims about "dire consequences" in other respects?

A. Yes. APS makes other generic claims against competitive power suppliers. Its criticisms over possible reliability problems with competitive power under PPAs are issues settled long ago. The record for pay-for-performance contracts is exceptional on availability. On the issue of price stability, the APS premise is that, if competitive power is procured, it must be at spot prices which, in turn, reflect spot gas prices. That premise is unfounded. Competitive power producers are willing to offer fixed-formula prices that shield ratepayers from fuel price risks.

Q. What is your response to the third APS argument?

A. My response is that granting the variance will indeed harm competition and, thereby, make a difference in market prices. The APS arguments that the Commission would have to accept to grant the variance are so unreasonable that competitive power suppliers and their investors could only conclude that the door has been shut on opportunities in Arizona.

The Commission would have to agree with APS that there are no competitive offers worthy of evaluation. This, despite the fact that RFPs routinely bring forth abundant bids. For example, in January 2000, Public Service Company of

Colorado (PSCO) issued an RFP for 1,365 MW. In response, PSCO received 50 bids totaling 9,000 MW. PSCO decided to accept 12 bids totaling 1,995 MW, 46% more megawatts than it had originally sought.

And despite the fact that a neighboring utility, Nevada Power, just announced two long-term agreements on March 22, 2002 which it believes could reduce a requested rate increase of over 20% to 8.8%. These two agreements are with competitive power suppliers, Williams Energy and Reliant Energy.[1] Indeed, on March 25, 2002, Williams announced it had entered into exclusive negotiations with Nevada Power on a broader arrangement involving fuel supply, new assets, and risk management.[2]

Moreover, the Commission would have to agree with APS that there are no competitive alternatives to APS own power plants. APS gained market-based rate authority from FERC by claiming that it faced competition from throughout the Western U.S. from over 70,000 MW of generation and that its own generation accounted for only 5.2% of the total market.[3] How can APS now claim it has no competitors without giving up its market-based rates?

[1] News Release, *Nevada Power Company Reaches Agreements for Long-Term Power* (March 22, 2002).
[2] News Release, *Williams, MidAmerican and Nevada Power Negotiate First Risk Management Contract for Regulated Utility* (March 25, 2002).
[3] *See* Updated Market Power Study of Arizona Public Service Company's for Electric Tariff, Original Volume No. 3 in Docket No. ER00-1875-000 (2001).

And again, the Commission would have to agree with APS that, assuming the market cannot fully respond in a single year (2003), it is necessary to grant a 29-year variance.

Q. What is your response to the fourth APS argument?

A. My response is that, by no stretch of the imagination, has APS shown that the Affiliate PPA is the best deal obtainable for Arizona ratepayers in terms of cost, risk, reliability, and environmental performance. The APS Affiliate PPA is a cost-plus offer such that the cost to ratepayers in the future is unknown, ratepayers shoulder all the risks, and there is no penalty for poor reliability performance. In sharp contrast, for 20 years now, competitive power suppliers have shown that they are willing to sign PPAs with predictable fixed-formula pricing, to take most risks off the shoulders of ratepayers, and to agree to automatic penalties if reliability performance is not as promised.

Q. Do you believe it is in the best interests of Arizona ratepayers for APS to solicit competitive offers?

A. Yes. Indeed, the APS Affiliate PPA is such a bad deal for Arizona ratepayers, that it is likely, if not a certainty, that a better deal could be obtained from the market. Despite all its rhetoric, APS offers none of the guarantees of price stability and performance reliability that are typical of a PPA obtained in a competitive market ("Market PPA"). This is seen in three crucial contract terms:

1. Fuel Cost Risk: The APS Affiliate PPA lists a Base Fuel Charge of 1.74 cents per kwh for the so-called Dedicated Units, but this does not mean fuel costs are "fixed" in any sense of the word. Under the APS offer, fuel costs, whatever they may be, are a pass-through to ratepayers. At a minimum, a Market PPA would offer ratepayers lower risk by guaranteeing a heat rate and by setting fuel prices to a published market price index. If desired, a Market PPA could fix fuel prices in part or in whole.
2. Capital Cost Risk: The APS Affiliate PPA lists a specific Facilities Charge for 2002, 2003, and 2004 (It is $67.1 million a month in 2004.) for the so-called Dedicated Units, but this in no way means that capital costs are "fixed" because, again, going forward the APS Affiliate PPA is essentially a cost-plus pass-through. A Market PPA would offer ratepayers lower risk by offering a fixed capacity price over the full term of the contract.
3. Reliability Performance Risk: The APS Affiliate PPA lists a minimum availability for its so-called Dedicated Units, but there is no penalty if that availability is not achieved. A Market PPA would offer ratepayers lower risk through a guaranteed availability for each power plant and an explicit penalty on capacity price if that guarantee is not met.

Q. Does APS offer any evidence to support its claim that its Affiliate PPA is superior to offers obtainable from the competitive market?

A. Yes. An expert witness for APS, Dr. Hieronymus, points to a benchmark study done in a proceeding currently before FERC concerning an affiliate PPA for Pacific Gas & Electric ("PG&E"), a utility serving Northern California.

Q. Is it convincing evidence?

A. No. There are four reasons for my conclusion that the evidence is unconvincing, as used here by APS.

First, Dr. Hieronymus fails to support the only original analysis in his Testimony: the calculation of the cost of the APS Affiliate PPA. He concludes that the levelized nominal cost of the APS Affiliate PPA is $50.51/MWH. But at least five questions about key assumptions remain unanswered. Why does Dr. Hieronymus spread costs over 25,531 GWH from the Dedicated Units, instead of the 21,090 GWH called for in the APS Affiliate PPA? On what basis does he assert that the cost-plus capacity price in the APS Affiliate PPA will escalate at 1.5% *below* the general rate of inflation? Why does he levelize over 10 years as opposed to the 14-year original term of the PPA, or even over its full 29-year term? Why does he use coal escalation for the Mountain Region, which shows coal prices steadily declining in real terms, instead of coal prices for the region more narrowly focused on Arizona, which show coal prices initially rising in real terms? Why does he fail to add a cost for ancillary services as was done for the benchmark contracts in the PG&E analysis on which he relies?

Q. Are the answers to these questions important?

A. Yes. They are very important. These five unanswered questions reveal that Dr. Hieronymus has significantly understated the cost of the APS Affiliate PPA. With reasonable answers to these questions, the cost of the APS Affiliate PPA is increased to $64.54/MWH, 28% higher than Dr. Hieronymus' original estimate of $50.51/MWH. (Exhibit No.__(CRR-2)) By reasonable answers I mean: (a) use the 21,090 GWH from the APS Affiliate PPA; (b) escalate the cost-plus capacity price with inflation; (c) levelize the cost over the 13-years of the original PPA term he shows in his table; (d) use the coal price escalation for Arizona; and (e) add the same $2.50/MWH for ancillary services added to the contracts used as a benchmark for the PG&E affiliate PPA.

Q. What is the second of your four reasons why the APS evidence is unconvincing?

A. The second reason is that Dr. Hieronymus compares the estimated cost of the APS Affiliate PPA to just one of many points of comparison provided in the PG&E benchmark study. Since the APS Affiliate PPA is touted as a *portfolio* offer, I think it is best to compare it to the cost of the *optimal portfolio* of benchmark contracts presented in the PG&E analysis, which is estimated to be $56.82/MWH. If the APS Affiliate PPA is compared to the optimal portfolio in the PG&E analysis, then the APS Affiliate PPA, as corrected, is up to 14% more expensive ($64.54/MWH for APS vs. $56.82/MWH for the benchmark optimal portfolio).

Q. What is your third reason why the APS evidence is unconvincing?

A. The third reason is that Dr. Hieronymus should have compared the APS Affiliate PPA to the PG&E affiliate PPA. If he did, it would be clear that PG&E is offering a much better deal to its ratepayers, on both price and non-price terms, than APS is offering its Arizona ratepayers.

Q. What is the fourth reason you find the APS evidence to be unconvincing?

A. The fourth reason is that Dr. Hieronymus fails to adjust the benchmark comparison for the fact that the benchmark contracts, in general, offer superior price stability and reliability performance guarantees than APS does in its Affiliate PPA. It is clear that a benchmark analysis must assure the contracts are comparable in both price and non-price terms. Dr. Hieronymus does not properly assure such comparability on non-price terms.

Q. For perspective, where did these benchmark contracts come from?

A. All the benchmark contracts were signed by the California Department of Water Resources ("CA DWR") to help diffuse the California crisis in 2000/2001.

Q. Does this influence how they can be used as a benchmark?

A. Yes. The CA DWR PPAs were signed in the midst of a crisis that clearly should be expected to result in higher contract prices. At the time of the CA DWR negotiations, competitive power suppliers had not been and were not being paid in California. What is the right price for power when there is a huge credit risk? FERC itself has put that credit risk premium at 10%.[4] Also at that time, there were huge political risks of doing business in California. The California crisis became the focus of political battles at the highest levels of the State and Federal Governments. What political risk premium is appropriate? Natural gas prices had spiked to unprecedented levels, much higher than those in the rest of the U.S. What gas price premium is appropriate? In sum, the circumstances in which the CA DWR PPAs were signed should be expected to increase contract prices. And, equally important, these are not at all the circumstances in Arizona at that time nor, more relevantly, today.

Q. Did you review any other APS evidence on possible competitive offers from the market?

A. Yes. Dr. Hieronymus presented capacity and energy prices he would expect from new competitive power suppliers: (a) for a new combined cycle (CC), first year prices of \$120/kw-year and \$25/MWH; and (b) for a new combustion turbine (CT), first year prices of \$60/kw-year and \$35/MWH.[5] The Summary Table below compares the starting-point prices from the APS Affiliate PPA to these prices. The comparison is made at nine different capacity factors.

[4] *See San Diego Gas and Electric Company vs. Sellers of Energy and Ancillary Service*, 95 FERC ¶ 61,418 (2001), at page 35.

[5] *See* Direct Testimony of William H. Hieronymus at page 9 lines 1 to 11, and footnote 3.

Summary Table

UNIT COST OF GENERATION OPTIONS

Capacity Factor	APS Affiliate PPA ($/MWH)	New CC ($/MWH)	New CT ($/MWH)
10%	$ 211.46	$ 161.99	**$ 103.49**
20%	$ 114.43	$ 93.49	**$ 69.25**
30%	$ 82.09	$ 70.66	**$ 57.83**
40%	$ 65.92	$ 59.25	**$ 52.12**
50%	$ 56.21	$ 52.40	**$ 48.70**
60%	$ 49.74	$ 47.83	**$ 46.42**
70%	$ 45.12	**$ 44.57**	$ 44.78
80%	**$ 41.66**	$ 42.12	$ 43.56
90%	**$ 38.96**	$ 40.22	$ 42.61
Weighted Average	$ 56.21	$ 52.40	$ 48.70

Sources: PPA between PWCC and APS, p. SS3, Data for 2004.
Hieronymus Direct, p.9.

Q. What does the Summary Table show?

A. The Summary Table shows three things. First, using Dr. Hieronymus' estimates of costs for new units, the APS Affiliate PPA starting-point price is the lowest cost choice at only the two highest capacity factors, and by only a small margin at that. The point I draw from this table is that the APS Affiliate PPA starting-point prices are readily beatable by competitors.

Second, since the two high capacity factors are much higher than the system load factor (about 50%), buying all power under the Affiliate PPA is the highest cost package or portfolio. This is seen by comparing the Weighted Average costs at the bottom of the Summary Table; at $56.21/MWH, the APS Affiliate package is more expensive than the all-CC or all-CT packages.

Third, the lowest cost to ratepayers actually is achieved by picking and choosing from all three options, not by going exclusively with any one option. The optimal portfolio is the mix of the options shown in bold. The point I take from this is that, by bundling power supply in the APS Affiliate PPA, APS is denying Arizona ratepayers a chance to get the lowest cost.

I should add that, simply by lowering the capacity price for combined cycle from Dr. Hieronymus' $120/kw-year to $100/kw-year, the APS Affiliate PPA is not part of the optimal portfolio at all.

Q. Are you saying Dr. Hieronymus' prices are a definitive estimate of prices obtainable in a Market PPA?

A. No. The only way to know what the market will offer is to conduct an actual RFP, or to enter into arms-length negotiations for bilateral contracts. However, I am saying that it is clearly worth issuing an RFP because even the cost-plus starting point for prices in the APS Affiliate PPA are just not that attractive.

Q. Do you have any additional concerns with the APS Affiliate PPA?

A. Yes. I have a concern that APS outsources responsibility for all purchases and for dispatch to PWCC. My specific concern is that this will institutionalize self dealing.

Q. Do you have any recommendations for the Commission?

A. Yes. Based on my Testimony, I recommend that the Commission do the following:

1. Deny both the request for a variance and for approval of the APS Affiliate PPA.
2. Order APS to maintain responsibility for power purchases and dispatch, and not outsource that responsibility to PWCC.
3. Set payments for all present and formerly-owned APS generation equal to that based on traditional cost-plus rate making, until APS conducts competitive procurement for all its Standard Offer needs and APS generation is selected through that procurement.
4. Order APS to competitively procure, through competitive bids and negotiated contracts, all its Standard Offer capacity and energy needs. The goal will be to get the best deal for ratepayers in terms of price, risk, reliability, and environmental performance.
5. For the competitive bids, APS should issue RFPs, with: (a) a draft RFP to be prepared by APS within 15 days after the Order; (b) Third-Party Evaluator and Intervenor review completed in 30 days after the Order; (c) the RFP issued in 40 days after the Order; and (d) bids due 75 days after the Order. This schedule will not materially prejudice APS, but it will enable the Commission to base its decision on *facts* about the extent of wholesale competition rather than on APS' assertions.

6. The on-line dates of winning bidders should be staggered to get the best deal for ratepayers. Bids that offer the best deal to ratepayers and can be on-line in 2003 should be winners. Bids that offer the best deal to ratepayers, but cannot be on-line until later (2004, 2005, etc.) should be winners too; that is, their later on-line dates should be allowed. The on-line dates would dictate the priority for executing final contracts. Length of contracts should also be varied in the context of a risk management plan.
7. PWCC should be required to bid each of its facilities separately into the RFP. Each of PWCC's bids will be evaluated on the same terms as all other bids and, if it wins, PWCC will be held to its bid, as would any bidder.
8. Since PWCC is a bidder, the Commission should insist on pre-approving a Third Party Evaluator to serve along with the Commission Staff and APS on the Bid Evaluation Team.
9. If the Commission believes that *non-gas-fired resources* must be included in the portfolio that serves Standard Offer customers, then APS will issue an RFP with a portion set aside for non-gas-fired power. The on-line dates may be staggered to accommodate longer lead times.

III. APS HAS FAILED TO SHOW ITS AFFILIATE PPA OFFERS ARIZONA RATEPAYERS THE BEST DEAL IN TERMS OF COST, RISK, RELIABILITY, AND ENVIRONMENTAL PERFORMANCE.

A. **The costs to ratepayers of the APS Affiliate PPA are unknown, all risks have been shifted to ratepayers, and reliability is not guaranteed. The APS Affiliate PPA is such a bad deal it is highly likely, if not a certainty, that Arizona ratepayers would get a better deal in a PPA offered by a competitive power producer.**

Q. Before we discuss the APS Affiliate PPA, please list some of the typical contract terms in a PPA that is negotiated at arm's length and that would reflect market terms and conditions ("a Market PPA").

A. A Market PPA typically would offer significant price stability and pay-for-performance reliability features that would benefit Arizona ratepayers. A Market PPA would include some or all of the following six provisions:

(a) A capacity payment that is fixed in absolute terms (e.g., $100/kw-year or $60/kw-year for the entire term of the PPA), or adjusted for inflation each year over the term;

(b) A capacity payment that is tied to a performance guarantee in the form of a guaranteed availability at or above 90% (i.e., the full capacity payment is made if, and only if, availability meets or exceeds the guarantee, and the payment is reduced automatically if the guarantee is not met);

(c) Or, if requested, protection could also be offered in the form of liquidated damages (i.e., if the availability guarantee is not met, the supplier will compensate the buyer for costs in excess of the contract price incurred to replace the power);

(d) A Force Majeure definition limited to general, uncontrollable factors such as Acts of God, etc.;

(e) Fixed and variable operation and maintenance ("O&M") prices that would increase only with changes in inflation over time; and

(f) Either a fixed-formula energy price (e.g., guaranteed heat rate multiplied by a fuel price indexed to some publicly available gauge of changing prices) or, if requested to assure price stability, an energy price fixed in part or in whole.

Q. How do these features protect ratepayers?

A. These features protect ratepayers because, instead of the open-ended risk they face under the APS Affiliate PPA, ratepayer risk is bounded. Moreover, these features limit risk in total because risk is allocated to the party best able to manage it. For example, rather than have Arizona ratepayers face capital cost risk, that risk is shifted back to equipment manufacturers and engineering/construction firms.

Q. Does the APS Affiliate PPA include these ratepayer protections?

A. No. Despite all the rhetoric in the Testimony of APS' witnesses, I see almost none of these price stability or pay-for-performance reliability features in the

APS Affiliate PPA itself. Indeed, I have significant concerns about what exactly APS is getting the Arizona ratepayer into.

1. The APS Affiliate PPA offers no assurance of price stability because it shifts all risks for all costs onto Arizona ratepayers.

Q. Did APS claim the Affiliate PPA offers price stability superior to that obtainable from the competitive market?

A. Yes. APS witnesses state that the APS Affiliate PPA provides its customers with price stability, implying that power prices are somehow fixed over time. A close examination of the PPA reveals costs are not fixed, but rather, that ratepayers will pay whatever costs are incurred by PWCC. That is, Arizona ratepayers bear the risk of shifts in fuel costs, fixed costs, and all other costs.

Q. How, then, can APS think its Affiliate PPA is superior to the market on price stability?

A. APS simply presumes a cost-plus deal always beats the market. For example, Mr. Davis uses his estimate of long-run marginal cost (LRMC) to conclude the Affiliate PPA, in the first six years, could yield hundreds of millions in savings.[6] Mr. Davis is presuming (a) competitive power producers could never offer a price less than his LRMC and (b) the utility's cost-plus price could never be above his LRMC.

Q. Are these presumptions reasonable?

A. No. For example, if the market never beats cost-plus prices, there would be no stranded costs.

Q. Please discuss why there is no price stability guarantee in the APS Affiliate PPA with respect to fuel cost?

A. In the PPA, the Base Fuel Charge ("BFC") is set at 1.74 cents per kwh from January 1, 2003 until the end of the Agreement. However, this does not mean that the fuel-related price of power is "fixed" in any sense of the term. This is because, the BFC is adjusted by the Fuel & Purchased Power Adjustment ("FPPA"). The FPPA is the average difference *projected* between the BFC and average fuel cost for the coming year, plus the *actual difference* between projected and actual average fuel cost from the previous year less some margin for off-system sales. The average fuel cost is set as the actual total fuel cost for the Dedicated Units divided by the total energy from those units. That is, the APS Affiliate PPA simply passes through fuel costs, whatever they are.

Q. What does APS include in the term fuel costs?

A. Total fuel costs are defined as follows:

> "[A]ll coal, gas including transportation, oil, nuclear fuel expenses, costs and benefits of fuel-related financial instruments, nuclear spent fuel costs, any applicable surcharges, purchased power costs associated with economic dispatch of the Dedicated Units, nuclear decommissioning expense to the extent it is not recovered from the System Benefits

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[6] *See* Direct Testimony of Jack E. Davis on behalf of Arizona Public Service Company in Docket No. E-01345A-01-0822, at pages 24 and 28.

> charge...and any other fuel related expenses, including but not limited to costs associated with emissions allowances."[7]

Again, the effect is that whatever fuel-related costs PWCC incurs are simply passed through to Arizona ratepayers.

Q. How does this compare to what is typical in a Market PPA?

A. As I noted above, a Market PPA typically offers fixed formula fuel-related (energy) prices. This could take the form of a guaranteed heat rate multiplied by a fuel price indexed to a published gauge of fuel prices. The guaranteed heat rate protects ratepayers from poor fuel efficiencies. Tying the fuel price to a published index protects ratepayers from fuel prices in the Market PPA getting out of line with market fuel prices.

As also noted above, if ratepayers want it, it is not uncommon for energy prices to be fixed in part or in whole. APS witnesses make much of the fact that natural gas prices are more volatile than those for coal. However, a Market PPA could include some extent of fixed energy prices that mitigate natural gas price volatility. The power supplier would be likely to back that fixed price offer with a matching fuel supply contract, but, even if it does not, that is not the ratepayer's problem.

Q. Do Arizona ratepayers get these protections in the APS Affiliate PPA?

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[7] Purchase Power Agreement between Pinnacle West Capital Corporation and Arizona Public Service Company at Service Schedule Revised Attachment #2.

A. Absolutely not. APS does not guarantee heat rates. Again, the Arizona ratepayer bears all the risk of poor heat rate performance under the APS Affiliate PPA. And Arizona ratepayers get no protection from above-market fuel costs, through the APS Affiliate PPA. Under the FPPA, for example, if the PWCC/PWEC cost of gas were to rise to $5/MMBTU, and the market index price was only $4/MMBTU, the above market price (25% or $1/MMBTU) would be passed through to ratepayers. All risks of changes in fuel costs would be borne solely by the ratepayers, who are in no position to mitigate this risk as APS or a competitive power supplier would be.

Q. What about equipment or "capital related costs?"

A. It is not just fuel cost risk that would be shifted to Arizona ratepayers. The Facilities Charge, which covers capital-related costs, also functions in a similar way to shift fixed cost risks from APS/PWCC to the ratepayers. These costs are not calculated exactly like the FPPA, instead they are estimated for three-year periods. Nonetheless, if capital costs are projected to increase, ratepayers will pay those increases.

The APS Affiliate PPA includes a Facilities Charge of $63.6 million per month in 2003 and $67.1 million per month in 2004, and then refers the reader to Attachment #1 for the Facilities Charge in subsequent years. The Facilities Charge includes all annual non-fuel expenses associated with the Dedicated Units. This includes capital costs, capital improvements, materials and supplies, O&M costs, Administrative and General expenses, taxes, and depreciation expenses. While the use of a three-year projection might temporarily delay a pass-through, the Facilities Charge is essentially a cost-plus pass-through of all capital-related costs to Arizona ratepayers.

Q. For these capital-related costs, what ratepayer protections are typical in a Market PPA?

A. In a standard Market PPA, it is typical that the capacity charge is fixed (e.g., $100/kw-year or $60/kw-yr), or it may increase with inflation. If there are equipment failures or cost overruns or capital improvements over time that were not anticipated in the fixed price, the competitive power supplier, not ratepayers, would take the loss.

Q. So do Arizona ratepayers get risk protection from the APS Affiliate PPA?

A. No they do not. Again, all capital-related cost increases are simply passed through to ratepayers. For example, the risks of complying with environmental regulations are passed through the PPA to be borne by Arizona ratepayers. Section 9.1 (C) states, "[i]f during the term of this Agreement, any material increased costs are associated with the Dedicated Units as a result of any Governmental Authority or any judicial order, APS shall be responsible for all such increased costs through an annualized charge."

For example, if the Navajo and Four Corners units are needed to be modified to comply with air quality standards, the expense could be immediately charged to the ratepayers. Only if PWCC determined that these costs arose "directly out of the operations and/or administration of the Dedicated Units,"[8] are the expenses the responsibility of PWEC. Otherwise the costs are immediately passed on to consumers.

Q. What environmental costs could be passed-through?

A. A quick review of APS' Form 10K-405 filed March 14, 2001 revealed these eight items:

1. The Grand Canyon Visibility Transport Commission completed a study on visibility impairment in sixteen Class I areas (including areas near where APS sites the Navajo, Cholla, and Four Corners generating station) on June 10, 1996. Since then, the EPA announced the final haze rules requiring all states to submit an implementation plan to eliminate all man-made emissions causing visibility impairment by 2008.[9] Or, each state can submit an implementation plan by 2003 with milestones for 2003, 2008, 2013, and 2018.[10] The EPA is currently reviewing an Annex to the Visibility Commission's recommendations which would require the same milestones,

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[8] *See* Purchase Power Agreement between Pinnacle West Capital Corporation and Pinnacle West Energy Corporation Article 9 Section 9.1 (H).

[9] Final haze rules announced on April 22, 1999.

[10] If, the milestones set in the implementation plan are met then there will be no further emissions reductions requirements. If the milestones are not met than emissions credits will be issued.

but the implementation plan would not be required until 2008. Since, the Annex plan is not yet approved and the State will have the ultimate decision, APS states, "the actual impact on us cannot be determined at this time."

2. In July of 1997, the EPA promulgated the final National Ambient Air Quality Standards for ozone and particulate matter. These new standards would make the emissions laws more stringent. On February 27, 2001 the US Supreme Court found the standards to be unlawful and remanded the issue for consideration. Because, the actual level of emissions controls is unknown, APS states, "...we currently cannot estimate the capital expenditures, if any, which would result from the final rules."

3. APS alludes to the fact that mercury emissions and other hazardous air pollutants from coal and oil-fired power plants will be regulated. It suspects the EPA will propose a specific rule by 2003, finalize it by 2004, and require compliance by 2008. Again, APS states, "...we cannot currently estimate the capital expenditures, if any, which may be required".

4. In September 1999, the EPA gave a Federal Implementation Plan (FIP) to set air quality standards at Navajo and Four Corners (as well as other non-APS power plants). APS believes that, because of the FIP, these plants will require minor modifications.

5. The Comprehensive Environmental Response, Compensation, and Liability Act (Superfund) establishes responsibility for clean up of hazardous substances contaminating air, water, and land. APS has been found to be a potentially responsible party for the Indian Bend Wash Superfund Site, South Area. It is in that area that their Octillo Power Plant is located. APS is currently investigating the amount of contamination for which it will be responsible.

6. In July of 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. On October 12 and 13 of 1995, Four Corners and Navajo Generating Station participants filed lawsuits requesting judicial orders as to whether or not these acts are applicable to their operations. On October 18, 1995 the Navajo Nation and APS' generating plants agreed to indefinitely stay the proceeding and to pursue the dispute without litigation. The costs of the outcome of this matter are still undetermined.

7. In April 2000, the Navajo Tribal Council approved operating permit regulations under the Navajo Nation Air Pollution Prevention and Control Act. APS asserted that its Four Corners and Navajo plants were exempt from these operating permits and filed a petition with the Navajo Supreme Court. This issue is still pending decision.

8. APS is involved in at least two groundwater rights cases. The Lower Gila River Watershed case dates back to 1986 and APS has four power plants located within the geographic area subject to the summons. Litigation is continuing in trial court, but there is no trial date set. The other case involves the Little Colorado River Watershed and the groundwater resources utilized by Cholla. The parties are in the process of settlement negotiations. However, the results of both cases are, as yet, indeterminate.

Q. Would a Market PPA expose ratepayers to risks of paying similar costs?

A. No. Generally, competitive power suppliers bear the risk of changes to environmental regulations.

Q. Are there other concerns about cost pass-throughs related to the Dedicated Units?

A. Yes. Arizona ratepayers are at risk for poor performance and poor decisions at the Dedicated Units. For example, the PPA between PWCC and PWEC, while very similar to the APS/PWCC PPA, contains one additional element that I believe could raise costs for ratepayers. Section 3.1 of the Service Schedule states:

> "PWCC will have full and exclusive dispatch rights to all Dedicated Units during the term of the Agreement, *provided, however, that PWCC will be subject to and abide by any 'must run' or 'minimum take' requirements, or similar or related requirements, as to the operations of the Dedicated Units.*" [Emphasis added]

This provision does not appear in the PPA between APS and PWCC but it has implications for APS. Because PWCC is only responsible for procuring APS' requirements, and because costs are not an issue, these must-run and minimum-take costs would most likely end up being charged to the ratepayers of APS. My concern is not with these costs *per se*, but rather that ratepayer responsibility is so open-ended.

Q. Are there other concerns about cost pass-throughs beyond those related to the Dedicated Units?

A. Yes. Other costs in the PPA are simply passed-through when they are incurred and will be immediately billed to ratepayers. Charges that are direct pass-throughs include Supplemental and Replacement Energy Products as well as costs for Ancillary Services, transmission service, and transmission losses incurred during the delivery of energy. APS ratepayers are responsible for all costs of acquiring these services.

Q. Of these, is one of particular concern?

A. Yes. I am particularly concerned with the provision for Replacement Energy. It allows PWCC to purchase power and directly pass-through the costs of that power. My concern is Section 3.4, which states: "[i]n the event of non-performance by parties that are under contractual commitments, PWCC shall use commercially reasonable efforts to obtain Replacement Energy Products."

Of course, the Dedicated Units are "under contractual commitment;" that is, they are under the PWCC PPA with PWEC. Any time there is a failure of the Dedicated Units, PWCC could simply purchase Replacement Energy and sell it to APS at cost. That is, despite the fact that the Replacement Energy was needed because of poor reliability performance at the Dedicated Units, ratepayers must pay that cost. In this way Arizona ratepayers are contractually liable for the risk of poor performance of the Dedicated Units.

Q. What is the bottom line implication of this lack of ratepayer protections in the APS Affiliate PPA?

A. The bottom line is that, with all these price risks laid on the shoulders of Arizona ratepayers, the APS Affiliate PPA clearly does not offer the best deal to Arizona ratepayers over its 29-year term. A Market PPA offers clearly superior price stability guarantees.

2. The APS Affiliate PPA offers no reliability guarantees for the power supplied by the so-called "Dedicated Units."

Q. Did APS claim to offer reliability guarantees superior to that obtainable in the competitive market?

A. Yes.

Q. Do you see such reliability guarantees in the APS Affiliate PPA?

A. No. I see no reliability guarantee for any of the Dedicated Units. In the Service Schedule attached to the APS Affiliate PPA, I see section 3.2.3 entitled "Minimum Availability of Dedicated Units." That section states that, in 2003 and thereafter, PWCC shall make available up to 4,720 MW of capacity from Dedicated Units at system peak, subject to retirements of the Dedicated Units. This is not much to offer. Availability at system peak does not guarantee availability at any other time of the year. The next section (Section 3.2.3.2) purports to guarantee energy production from the Dedicated Units of 21,090 GWH annually, which would mean an average capacity factor of 51%. That may match some estimate of system load factor, but that does not constitute a reliability performance guarantee.

Equally important, I see no penalty if PWCC fails to actually provide the 4,720 MW at system peak. I see no link between even this limited reliability performance offer to the payment of the capacity payment (the "Facilities Charge").

Q. Do you see any penalties in the APS Affiliate PPA?

A. Yes. I do see what appears to be a penalty if PWCC fails to meet the Full Load Requirements of APS Standard Offer customers now and in the future. But, in reality, if PWCC fails to perform, here, too, it is the APS ratepayer that will be penalized. It is true that, if PWCC fails to meet these Full Load Requirements, PWCC is responsible for the cost in excess of the Contract Price that APS incurs to replace the missing power supply. However, this does not translate into a reliability performance guarantee for the Dedicated Units because PWCC is free to buy power to assure these Full Load Requirements are met and the cost of those purchases would be passed-through as Replacement Energy, as discussed above. Indeed, the APS Affiliate PPA gives PWCC the incentive to pay any price for power to avoid this penalty since there is no limit on what can be passed through to Arizona ratepayers.

For example, assume that 944 MW or 20% of the 4,720 MW of Dedicated Units are out because of forced outages for a given week in the summer. I see no penalty to PWCC for the failure to perform reliably due to these forced outages. Instead, PWCC could go to the market and buy power to replace the 20% shortfall created by the forced outages of the Dedicated Units and pass that cost, whatever it is, onto Arizona ratepayers as Replacement Energy.

Q. Do you see any other contract terms that further undermine any possible penalty for poor reliability performance from the Dedicated Units?

A. Yes. PWCC could also point to its Force Majeure clause and say that all the forced outages are excused. This is because the APS Affiliate PPA very broadly defines Force Majeure to include "material failure of performance by any PWCC supplier, including failures as a result of Force Majeure, which results in a shutdown or material reduction of any of the generation capacity or output owned or controlled by PWCC or a PWCC Affiliate."[11] This would excuse a very wide range of events that cause problems for PWCC. And, indeed, this same favorable definition of Force Majeure is included in the companion PPA between PWCC and PWEC, the affiliate that controls all the Dedicated Units.

Q. Do other contract provisions raise concerns about the Dedicated Units?

A. Yes. The strength of the PWEC/PWCC commitment to provide power from the Dedicated Units under the contract is not guaranteed because PWCC has discretion over retirements. Section 3.2.3.1 of the Service Schedule states "PWCC shall make Capacity from the Dedicated Units available as follows...the lesser of 4720 MW at system peak or actual load at system peak, subject to adjustment as Dedicated Units are retired." There is no schedule for retirement of the units provided so there is no way of knowing when this will happen. That is, the Commission is being asked to find the APS Affiliate PPA is prudent, and yet APS has not even stated for how long it guarantees the Dedicated Units will provide service.

Furthermore, despite the competitive bidding requirement, if units are retired and PWCC does not have enough capacity to supply the full load requirements of APS, it may simply obtain the extra energy from the market as

[11] *See* Purchase Power Agreement between Pinnacle West Capital Corporation and Arizona Public Service Company at Exhibit A.

"Supplemental Energy Products." This cost is directly passed through to the ratepayers, providing no assurance that the cost of these products is competitive.

Terms such as this one for Supplemental Energy are troubling because they could institutionalize self-dealing. PWCC controls the competitive bidding process and can purchase Supplemental Energy to substitute for or supplement power from the Dedicated Units. There is nothing to prevent PWCC from purchasing power from other units controlled or built by PWEC. The Commission should be very concerned that the APS Affiliate PPA undermines its authority to judge the prudence of APS power purchases over time.

Q. Please explain how the Affiliate PPA might undermine the Commission's authority.

A. My concern is with how the Commission's ruling on the Affiliate PPA today affects its ability to review actions by PWCC in the future. For example, say PWCC declares that it must buy Supplemental Energy from a new 500 MW unit built by an affiliate in 2005. What is the Commission's authority to judge the prudence of the purchase? Will PWCC argue that the Commission has already pre-approved that purchase by finding the Affiliate PPA to be prudent today?

Similarly, with respect to Replacement Energy purchased to compensate for poor performance at the Dedicated Units, will PWCC argue that the Commission has pre-approved the prudence of those purchases? Will PWCC argue the Commission has no authority to judge the performance of the Dedicated Units?

The issue is this: how do the broad functions being outsourced to PWCC fit into the Commission's ongoing authority and procedures? That question remains unanswered.

B. Even putting aside its lack of price stability and reliability performance guarantees, the starting-point prices in the APS Affiliate PPA are clearly beatable. Further, by offering a bundled power supply, APS denies Arizona ratepayers a chance to get the lowest cost.

Q. Can you compare the capacity price and energy price levels in the APS Affiliate PPA to that which you would expect from the competitive market?

A. Yes and no. The APS Affiliate PPA is a cost-plus contract so we cannot know what APS will actually charge Arizona ratepayers until after the fact. However, even putting this aside, it is clear that the starting-point prices in the APS Affiliate PPA are beatable in the market.

Q. Would you illustrate this point?

A. Yes. Under the APS Affiliate PPA, after the transfer of all units in 2003, the starting points for the capacity and energy prices, respectively, are \$171/kw-year and \$0.0174/kwh. An APS witness, Dr. Hieronymus, suggests that the likely capacity and energy prices for a new gas-fired combined cycle plant, respectively, are $120/kw-year and $25/MWH.[12] For a new simple cycle combustion turbine he suggests a capacity and energy price respectively, of $60/kw-year and $35/MWH.[13] Table One simply translates these prices into costs per megawatt hour at nine different capacity factors.

A capacity factor indicates how often a power plant is run; it is the equivalent of the percent of all hours in a year in which a power plant is run at its full capacity. It is important to compare prices at different capacity factors because, in reality, different power plants are run different portions of times to assure ratepayers' demand is met in all hours.

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[12] *See* Direct Testimony of William H. Hieronymus on behalf of Arizona Public Service Company in Docket No. E-01345A-01-0822 at page 9.

[13] Id. at page 9 lines 1 to 11. Dr. Hieronymus, in FN 3, states: "The costs of the combined cycle and peaking units in these examples are illustrative but are broadly representative of equipment market conditions in the past year."

Table One

UNIT COST OF GENERATION OPTIONS

Capacity Factor	APS Affiliate PPA ($/MWH)	New CC ($/MWH)	New CT ($/MWH)
10%	$ 211.46	$ 161.99	**$ 103.49**
20%	$ 114.43	$ 93.49	**$ 69.25**
30%	$ 82.09	$ 70.66	**$ 57.83**
40%	$ 65.92	$ 59.25	**$ 52.12**
50%	$ 56.21	$ 52.40	**$ 48.70**
60%	$ 49.74	$ 47.83	**$ 46.42**
70%	$ 45.12	**$ 44.57**	$ 44.78
80%	**$ 41.66**	$ 42.12	$ 43.56
90%	**$ 38.96**	$ 40.22	$ 42.61

Sources: PPA between PWCC and APS, p. SS3, Data for 2004
Hieronymus Direct, p.9.

As can be seen in Table One, for example, at a 50% capacity factor, the all-in starting-point price for the APS Affiliate PPA, the new combined cycle, and the new combustion turbine, respectively, are $56.21/MWH, $52.40/MWH, and $48.70/MWH.

Q. Can Table One be used to illustrate what choice is best for ratepayers?

A. Yes, but only as an illustration. Let us assume that, to serve ratepayers, we need 1 MW of capacity at each of the nine capacity factors. To get the lowest cost for ratepayers, we could just choose the option that has the lowest all-in cost at each capacity factor.

As shown in Table One, the APS Affiliate PPA is the lowest-cost choice at only two of the nine capacity factors. The combustion turbine and the combined cycle have lower all-in costs in the seven other capacity factors. Even when the

APS Affiliate PPA offers the lowest all-in price, the gas-fired competitors are close behind. At a 90% capacity factor, the combined cycle plant is just 3% more expensive. The point I take from this is that the APS Affiliate PPA starting-point prices are readily beatable by the market.

Q. Should we compare costs of a package of power plants rather than individual units?

A. Yes. Rather than compare the costs of individual units, we should look at the package or portfolio of power plants needed to serve ratepayers as a group. Table Two does this by showing the total annual costs to ratepayers if any of the three options (the Affiliate PPA, all new combined cycle, or all new combustion turbines) were used to satisfy the system's needs; that is, the total cost is the sum of the costs of the nine power plants run at different capacity factors. Note that Table Two assumes a 50% load factor (the average capacity factor for all nine units), which is nearly identical to the 51% load factor APS used for the APS Affiliate PPA.

Table Two

TOTAL COST OF GENERATION PORTFOLIOS

Capacity Factor	APS Affiliate PPA (Total $)	New CC (Total $)	New CT (Total $)
10%	$ 185,242	$ 141,900	**$ 90,660**
20%	$ 200,485	$ 163,800	**$ 121,320**
30%	$ 215,727	$ 185,700	**$ 151,980**
40%	$ 230,970	$ 207,600	**$ 182,640**
50%	$ 246,212	$ 229,500	**$ 213,300**
60%	$ 261,454	$ 251,400	**$ 243,960**
70%	$ 276,697	**$ 273,300**	$ 274,620
80%	**$ 291,939**	$ 295,200	$ 305,280
90%	**$ 307,182**	$ 317,100	$ 335,940
Total	$ 2,215,908	$ 2,065,500	$ 1,919,700
Optimal Portfolio		**$ 1,876,281**	

Source: See Table One.

Q. What does Table Two show?

A. Table Two shows the portfolio relying exclusively on the APS Affiliate PPA is the highest cost portfolio with a total annual cost to ratepayers of about $2.2 million. This compares to the total annual costs of an exclusive portfolio of either new combined cycle units or combustion turbines, which are $2.1 million and $1.9 million, respectively. Again, the point is that, using Dr. Hieronymus' own price estimates, the APS Affiliate PPA is the most expensive way to satisfy ratepayers in this illustration, not the cheapest.

More importantly, Table Two shows that costs are minimized when the three portfolios are mixed in an optimal portfolio. By optimal I mean, at each capacity factor, we pick the option with the lowest price per MWH. In this illustrative example, the mixed, optimal portfolio leads to charges to ratepayers of only $1.88 million which are about $340,000, or 15%, less than the charges from a portfolio that relies exclusively on the APS Affiliate PPA. The point I take from this is that, by bundling power plants in its Affiliate PPA, APS is denying Arizona ratepayers a chance to get the lowest cost.

Q. Why did you use estimates presented by Dr. Hieronymus, an expert witness engaged by APS?

A. I used them because I thought APS could not argue with estimates presented by its own expert.

Q. Do you agree with these estimates?

A. I think they are in the ballpark of actual prices that are typical from competitive power suppliers. My continued concern with all of this is that it is not an apples-to-apples comparison because the APS Affiliate PPA has non-price provisions that are inferior to what is likely to be offered if APS solicited competitive bids.

For example, take just the fact that the APS Affiliate PPA effectively has a 29-year term. With that term in a Market PPA, a competitive power producer could be more aggressive on financing. That more aggressive financing could, for example, lower the capacity price for a new combined cycle generating facility to about $100/kw-year.

Q. What would that lower capacity price do to the illustrative example above?

A. Using a $100/kw-year capacity price would only widen the gap between ratepayer costs with the APS Affiliate PPA and Market PPAs. That is, it would further demonstrate how bad a deal the APS Affiliate PPA is for APS' ratepayers.

I make this change and present the results in Table Three and Table Four. Now, in Table Three, the APS Affiliate PPA is never the lowest cost choice. The new competitive facilities are the lowest cost option at all nine capacity factors.

Table Three

UNIT COST OF GENERATION OPTIONS

Capacity Factor	APS Affiliate PPA ($/MWH)	New CC ($/MWH)	New CT ($/MWH)
10%	$ 211.46	$ 139.16	**$ 103.49**
20%	$ 114.43	$ 82.08	**$ 69.25**
30%	$ 82.09	$ 63.05	**$ 57.83**
40%	$ 65.92	$ 53.54	**$ 52.12**
50%	$ 56.21	**$ 47.83**	$ 48.70
60%	$ 49.74	**$ 44.03**	$ 46.42
70%	$ 45.12	**$ 41.31**	$ 44.78
80%	$ 41.66	**$ 39.27**	$ 43.56
90%	$ 38.96	**$ 37.68**	$ 42.61

Sources: PPA between PWCC and APS, p. SS3, Data for 2004
Hieronymus Direct, p. 9, with $100/kw-year for combined cycle.

Table Four shows the total costs of serving ratepayers with various portfolios of power plants. Again, the APS Affiliate Portfolio is the most expensive. And, now, the Affiliate PPA is not even part of the optimal portfolio.

Table Four

TOTAL COST OF GENERATION PORTFOLIOS

Load Factor	APS Affiliate PPA (Total $)	New CC (Total $)	New CT (Total $)
10%	$ 185,242	$ 121,900	**$ 90,660**
20%	$ 200,485	$ 143,800	**$ 121,320**
30%	$ 215,727	$ 165,700	**$ 151,980**
40%	$ 230,970	$ 187,600	**$ 182,640**
50%	$ 246,212	**$ 209,500**	$ 213,300
60%	$ 261,454	**$ 231,400**	$ 243,960
70%	$ 276,697	**$ 253,300**	$ 274,620
80%	$ 291,939	**$ 275,200**	$ 305,280
90%	$ 307,182	**$ 297,100**	$ 335,940
Total	$ 2,215,908	$ 1,885,500	$ 1,919,700
Optimal Portfolio		**$ 1,813,100**	

Source: See Table Three.

Q. Again, what conclusions do you draw from these illustrative cost comparisons?

A. They show two things. First, even putting aside the higher ratepayer risk associated with the APS Affiliate PPA, the starting-point prices are beatable by the market. Second, by bundling power supply in the APS Affiliate PPA, APS denies its ratepayers a chance to get the lowest cost power supply.

C. Given that APS' ratepayers would pay billions of dollars under the APS Affiliate PPA, those ratepayers surely deserve a more careful examination of the agreement's costs and benefits than that in the APS expert's benchmark analysis.

1. The benchmark analysis APS points to was used to justify an affiliate PPA for Pacific Gas & Electric (PG&E), which offered its ratepayers

a better deal than APS offers its ratepayers, most notably in terms of price stability and reliability performance.

Q. Does APS offer any evidence to support its claim that the APS Affiliate PPA is superior to offers obtainable from the competitive market?

A. It attempts to. APS points to a benchmark study done by another utility for its own affiliate PPA. The analysis was done by an expert, Mr. Eugene Meehan, who was asked to develop a benchmark for an affiliate PPA proposed by Pacific Gas & Electric (PG&E), a utility serving Northern California. (Exhibit No.__(CRR-3))

Q. Is it appropriate to point to another study rather than do an original analysis?

A. It could be, but the presentation by the APS expert, Dr. Hieronymus, is entirely inadequate.

Q. What makes it inadequate?

A. It is inadequate for at least four reasons.

First, Dr. Hieronymus fails to take the obvious and useful step of simply comparing the APS Affiliate PPA to the PG&E affiliate PPA. That comparison would tell Arizona ratepayers that APS offered them far less than PG&E offered its ratepayers, most notably with respect to price stability and reliability performance guarantees.

Second, Dr. Hieronymus fails to document his analysis and appears to have made calculation errors that led him to underestimate significantly even the "assumed" cost of the APS Affiliate PPA. I say "assumed" cost because there is no way of knowing the actual cost of the APS Affiliate PPA since it is a cost-plus contract.

Third, Dr. Hieronymus fails to prove that the assumed cost of the APS Affiliate PPA is lower than Mr. Meehan's calculated cost of the benchmark contracts. For example, Dr. Hieronymus fails to compare the assumed cost of the APS Affiliate PPA, which he calculated as a *portfolio cost*, to the *portfolio cost* presented for the benchmark contracts for PG&E. In addition, he ignored other information in the PG&E analysis such as the cost of fixed-price contracts accepted by CA DWR.

Fourth, Dr. Hieronymus fails to account for the fact that the non-price features of the benchmark contracts are superior to those in the APS Affiliate PPA. That is, he fails to assure the benchmark contracts are comparable to the APS Affiliate PPA.

Q. Let us talk first about the comparison of the APS and PG&E PPAs. What are the specific advantages you see for ratepayers in the PG&E affiliate PPA relative to the APS Affiliate PPA?

A. PG&E offers a lower price overall, but the primary advantages to ratepayers in the PG&E affiliate PPA are in terms of price stability and reliability performance guarantees.

Q. How do the overall prices compare?

A. Again, I can only compare the starting-point prices. With respect to capacity price, both PPAs have a starting-point of about $171/kw-year. With respect to the energy price, the PG&E starting point price is less than half of that offered by APS. PG&E generally offers an energy price of $8/MWH while APS offers $17.40/MWH. (Exhibit No.__(CRR-4)) As noted, however, the real advantage of the PG&E offer lies in the contractual limits put around that starting-point price; that is, the real advantage of the PG&E affiliate PPA is in terms of the price stability offer.

Q. How do the two offers differ in terms of price stability?

A. The PG&E offer to its ratepayers is far superior to the offer presented by APS. Again, the APS Affiliate PPA is a cost-plus offer so there are no limits on the capacity and energy prices that APS can charge its ratepayers. With the PG&E affiliate PPA, both the capacity and energy prices are escalated with inflation over time, and only specified additional costs can be passed through. Specified additional costs include items such as new electricity industry taxes and the cost of added security measures and decommissioning costs at the Diablo Canyon Nuclear Power Plant. While the PG&E affiliate PPA is not an airtight, fixed-formula price, it clearly offers more price stability to ratepayers than does the APS Affiliate PPA.

Q. How do the two offers compare in terms of reliability performance guarantees?

A. Again, the PG&E offer is far superior to the APS offer. One of the key features is that the capacity payment is dependent on an explicit penalty/bonus tied to availability. In the peak summer months, PG&E must achieve a 95% availability level for the hydro and nuclear plants it offers in its affiliate PPA. If PG&E fails to achieve 95%, its capacity payments are reduced by 1.5% for each 1% by which it misses the 95% guarantee. For example, if PG&E achieves only a 90% availability in the peak months, its capacity payments (which are highest at that time) are reduced by 7.5%. There is the potential for a bonus, too. If PG&E achieves 100% availability it would be paid a 7.5% bonus.

Q. Are there availability guarantees for the rest of the year in the PG&E affiliate PPA?

A. Yes. In the shoulder months, PG&E must achieve at least a 92% availability. In the off-peak period, PG&E must achieve a 90% or 91% availability.

Q. Are there other reliability performance guarantees in the PG&E affiliate PPA that are superior to those in the APS Affiliate PPA?

A. Yes. For perspective, note that the PG&E affiliate PPA is built up from a standard form contract developed by the Edison Electric Institute; it is EEI's *Master Power Purchase & Sale Agreement*. (Exhibit No.__(CRR-4)) In this context, the PG&E affiliate PPA requires payment of replacement costs in certain circumstances if PG&E fails to deliver the capacity and energy called for under the affiliate PPA. In addition, PG&E commits to refueling outages for Diablo Canyon that can be no more than 42 days. And with respect to the Force Majeure clause in the PG&E affiliate PPA, the clause is tighter in the sense that, for example, it does not excuse all performance problems due to supplier failures as does the APS Affiliate PPA.

Q. Are you saying that the PG&E affiliate PPA is ideal?

A. No. My point is that the PG&E affiliate PPA is superior to the APS Affiliate PPA. That is, PG&E offered its ratepayers a much better deal than APS offered Arizona ratepayers.

Q. Are there any other points of comparison that are important?

A. Yes. I think it is important to see that the PG&E affiliate PPA is not a requirements contract like the APS Affiliate PPA. Rather, it is a contract for services from 7,100 MW of specific power plant capacity, and this is one of the reasons it is a better deal. Also, the PG&E affiliate PPA is a 12-year contract as compared to the effective 29-year term that APS seeks here.

2. APS' expert fails to document his analysis and appears to have made several miscalculations that lead him to significantly underestimate the assumed cost of the APS Affiliate PPA.

Q. With respect to cost comparisons, what is the key analysis from Dr. Hieronymus, APS' expert?

A. Dr. Hieronymus' key analysis is his calculation of the levelized cost of the APS Affiliate PPA. He claims the nominal, levelized cost is $50.51/MWH. Indeed, this is his only original analysis. It is key because he compares this $50.51/MWH to Mr. Meehan's estimated costs for the benchmark contracts to conclude that the APS Affiliate PPA is in the public interest.

Q. Should Dr. Hieronymus have fully documented his analysis?

A. Yes, of course.

Q. Does Dr. Hieronymus fully document his analysis?

A. No. Dr. Hieronymus has three Exhibits, with Exhibit WHH-3 being the most important. When asked for information to support these Exhibits via a data response he says, in effect, it is self-contained. Specifically, here is the question and answer:

> 1.70 Please provide documents or other evidence supporting the information illustrated in Exhibits WHH-2, WHH-3 and WHH-4.
>
> RESPONSE:

> With respect to WHH-2, see answer to DR 1.65. With respect to WHH-3, the input real fuel prices are from Exhibit WHH-2 for oil and gas; the rest of the construction of the table is explained in footnotes 6 and 7 in Dr. Hieronymus' testimony (pp. 18-19). With respect to WHH-4, the source is indicated on the face of the exhibit.[14]

Q. In what specific ways is his documentation deficient?

A. Dr. Hieronymus' documentation in Exhibit WHH-3 is deficient in at least five ways. First, in the column entitled "Fuel," he calculates fuel cost by assuming 25,531 GWH are generated by the Dedicated Units. This level of operation is asserted in a footnote starting on page 18 of his Testimony, and there is no discussion of, let alone any justification for this estimate. Why does he use 25,531 GWH when the APS Affiliate PPA guarantees only 21,090 GWH? Why does he choose to artificially lower his assumed cost in this way? There are no answers because there is no documentation.

Second, in the column entitled "Capital," Dr. Hieronymus calculates the Facilities Charge under the APS Affiliate PPA. In 2003 and 2004, he correctly uses the charge specified by the PPA. In years thereafter he assumes the charges "escalate at inflation less 1.5 percent." We learn this, again, in the footnote on p.18. How did Dr. Hieronymus come up with this estimate? Why did APS not offer to escalate its capacity price with inflation as PG&E did? There are no answers because Dr. Hieronymus provides no documentation.

[14] Arizona Competitive Power Alliance's First Set of Data Requests, January 3, 2002 to Arizona Public Service Company's Request for a Variance of Certain Requirements of A.C.C. R14-2-1606 and Power Purchase Agreement in Docket No. E-01345A-01-0822.

Third, at the bottom of the column entitled "Nominal Cost/MWH," Dr. Hieronymus displays his estimated cost of $50.51/MWH and denotes it as "Lev. Nom." I presume he means it is a levelized nominal figure. While Dr. Hieronymus shows 13 years of pricing, his levelized nominal price appears to be based on just 10 years. Why did he levelize over only 10 years? This lowers his assumed cost for the APS Affiliate PPA. And, why did he not levelize over the full 29-year term of the PPA? There are no answers because Dr. Hieronymus provided no documentation.

Fourth, in the column entitled "Coal," he uses an EIA forecast for the Mountain Region.[15] EIA forecasts that coal prices for the Mountain Region will decline in real terms. At page 4, footnote 1, Dr. Hieronymus acknowledges coal prices in Arizona are higher, but says Arizona should have similar escalation. The EIA forecast for Arizona actually shows escalation that is different: coal prices go up in the near-term and are much more even over time in real dollars. Why did Dr. Hieronymus not use the EIA forecast for Arizona? There is no answer because there is no documentation.

Fifth, at page 8, line 13 Dr. Hieronymus asserts that the APS Affiliate PPA "includes reserves and ancillary services." This is not at all clear from reading the PWCC PPA or the PWEC PPA. Dr. Hieronymus is claiming, in effect, that

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[15] EIA's 2001 *Annual Energy Outlook* per Dr. Hieronymus except coal from supplemental Table 90, Arizona/New Mexico sub-bituminous coal prices.

ancillary services are free from the Dedicated Units. On what basis does he make this claim?

The claim is important because, if not correct, Dr. Hieronymus must add an estimate of ancillary services costs to his estimate of the APS Affiliate PPA cost. He must do this because such a cost is added by Mr. Meehan to the benchmark contracts. Specifically, Mr. Meehan adds $2.50/MWH.

Q. Are these five deficiencies important?

A. Yes, absolutely. As best I can, given the lack of documentation, I have replicated Dr. Hieronymus' calculation in Exhibit___(CRR-2). I find that correcting these deficiencies could reverse his conclusion. That is, the APS Affiliate PPA would be more expensive than the benchmark contracts.

The estimated assumed cost of the APS Affiliate PPA increases 23% to $62.04/MWH from Dr. Hieronymus' estimate of $50.51/MWH if I make four simple changes: (a) use 21,090 GWH as called for in the PPA; (b) escalate capital cost with inflation; (c) calculate the levelized charge over the full 13 years in his table; and (d) escalate coal prices using the EIA forecast for Arizona.

If I make a fifth change by adding $2.50/MWH to match Mr. Meehan's adder for ancillary services, the estimated cost increases further to $64.54/MWH, a 28% increase over Dr. Hieronymus' original estimate.

3. APS' expert has not demonstrated that his assumed cost of the APS Affiliate PPA is lower than the calculated cost of the benchmark contracts used in the PG&E analysis.

Q. Does Dr. Hieronymus present any independent analysis of the benchmark contracts?

A. No. He relies entirely on the analysis done by Mr. Meehan for PG&E.

Q. When it comes to comparing the cost of the APS Affiliate PPA to that of the benchmark contracts, what does Dr. Hieronymus say?

A. He concludes that the APS Affiliate PPA is clearly less expensive. Specifically, Dr. Hieronymus states:

> "The most thorough analysis of the DWR contracts of which I am aware was submitted to the FERC by Eugene Meehan of NERA on behalf of Pacific Gas & Electric on November 30, 2001 in Docket No. ER02-456-000. He concluded that the most representative group of DWR contracts for comparison to a long-term purchased power agreement (that was similar in most respects to the proposed PPA) has a levelized nominal price of $57/MWh for baseload capacity and $79/MWh for peaking capacity. I have calculated the cost of power from the Dedicated Units included in the proposed PPA on a similar basis and conclude that their cost (which, were it comparable in cost the DWR contracts would be between the baseload and peaking prices) is approximately $50.5/MWh.

Again, this demonstrates that the proposed contract is cheaper than the most similar group of contracts to which it can be compared."[16]

Q. Do you agree?

A. No. I disagree for three reasons: (a) as explained above, Dr. Hieronymus made calculation errors resulting in his underestimating the cost of the APS Affiliate PPA by up to 28%; (b) he used the wrong points of comparison from the Meehan analysis; and (c) he failed to account for the fact that the benchmark contracts are generally superior to the APS Affiliate PPA with respect to price stability and reliability performance guarantees.

Q. What do you mean Dr. Hieronymus drew the wrong point of comparison from Mr. Meehan's analysis?

A. Mr. Meehan compared the PG&E affiliate PPA to costs from several perspectives. Dr. Hieronymus is referring to just one of Mr. Meehan's calculations. Although he provided no citations in his quoted language, Dr. Hieronymus apparently is referring to page 15 of Mr. Meehan's Testimony where he gives a summary of the 11 contracts he used in his Comparison Group. That is where Mr. Meehan lists the prices of $57/MWH for base load contracts and $79/MWH for peaking contracts.

Given the corrections to Dr. Hieronymus' cost estimate for the APS Affiliate PPA, even in the context of this single reference to Mr. Meehan, he can no

[16]*See* Hieronymus Direct at page 5 line 21 to page 6 line 9.

longer claim that he is showing the APS Affiliate PPA to be less expensive than all the benchmark contracts. With costs in the $62.04/MWH to $64.54/MWH range, the APS price is no longer lower than the price of $57/MWH for the base load plants in Mr. Meehan's Comparison Group.

Q. What other comparison does Mr. Meehan provide?

A. Mr. Meehan presents many more points of comparison than the single reference to which Dr. Hieronymus apparently directs our attention. It is Mr. Meehan's attempt to develop a portfolio price that I think is particularly important here. I think it is important because the APS Affiliate PPA is presented and priced as a portfolio offer. That is, it offers a single price for a full range of base load and peaking services.

Mr. Meehan presents what he terms a "cross over" analysis in which he picks from the 11 Comparison Group contracts the optimal mix to provide a portfolio of service similar to that in the PG&E affiliate PPA. For this purpose he concludes that the best contracts include the base load contract with PacifiCorp and three peaking contracts with Sempra, Calpeak Midway, and Wellhead Power Gates. Mr. Meehan states, "[t]he weighted average cost of the optimal replacement portfolio using the base case gas price is $56.82/MWH."

If Dr. Hieronymus is limiting himself to numbers from Mr. Meehan's analysis, I would prefer that he use this one because it is an attempt to get a portfolio price and that is the right concept for comparison to the assumed cost of the APS Affiliate PPA. Moreover, using this portfolio cost means that Dr. Hieronymus can no longer say in any respect that the APS Affiliate PPA is less costly because his corrected, assumed cost is up to 14% higher than Mr. Meehan's portfolio cost for PG&E ($64.54 versus $56.82).

Q. Are there other aspects of the Meehan analysis that you think are relevant here?

A. Yes. Mr. Meehan excluded from his Comparison Group some fixed-price contracts because he believed they were signed at a time that would lock in high California gas prices. Given APS' repeated warning about price stability, I think it would have been useful for Dr. Hieronymus to discuss these contracts in his Testimony.

There are three fixed price contracts mentioned by Mr. Meehan. These contracts are with High Desert, Williams, and Calpine; Mr. Meehan estimates their costs to be, respectively, as $61/MWH, $72/MWH, and $64/MWH. While these contracts have many features other than the fact that they are fixed price, I think they are relevant for two reasons: (a) they support the view that, if gas price volatility is a concern for Arizona, there are significant competitive power producers willing to offer fixed-price service in whole or in part; and (b) that this fixed price service can be offered at competitive prices ($61 and $64, are less than the up to $64.54 assumed cost of the APS Affiliate PPA).

IV. APS FAILS TO PROVE A VARIANCE IS IN THE PUBLIC INTEREST.

A. Unless APS shows its 29-year Affiliate PPA resulted from prudent decision-making, APS simply cannot show the variance is in the public interest.

Q. Again, what is APS asking the Commission to do here?

A. APS is asking the Commission to find that: (a) its request for a waiver of the Electric Competition Rules is in the public interest; and (b) its PPA with PWCC is just and reasonable.

Q. What must APS demonstrate for the Commission to grant either request?

A. For the Commission to grant either request, APS must show that the PPA offers a superior deal for ratepayers, in terms of price and reliability, to that obtainable in the competitive market. As indicated by APS' frequent reference to the term "prudence," this case is best viewed as a prudence review of the APS Affiliate PPA. The variance cannot be in the public interest if the APS Affiliate PPA is not prudent.

Q. What is the heart of a prudence review?

A. What lies at the heart of any prudence review is the determination that a reasonable decision-making process was followed and that the process involved a comparison of alternatives based on information known or knowable at the time of the decision.

Q. Is this concept of prudence used widely?

A. Yes. Both FERC and other state commissions use this definition when reviewing prudence in cases before them.

Q. Can you point to a precedent at FERC?

A. Yes. In a 1992 decision, FERC ruled that the proper standard for judging prudence was that of a reasonable utility manager, which meant that decisions should be made given all known, or knowable alternatives. FERC stated:

> "When determining the prudence of a utility's transaction, the proper standard is that of the reasonable utility manger. As stated in *New England Power Co*. . . . 'In performing our duty to determine the prudence of specific costs, the appropriate test to be used is whether they are costs which a reasonable utility management . . . would have made, in good faith, under the same circumstances, and at the relevant point in time.' Utility managers are given 'broad discretion in conducting their business affairs' and incurring costs. Their decisions should be evaluated in light of factors which were, or should have been, known to them at the time, not on hindsight gained through after-the-fact occurrences."[17]

Furthermore, in a recent FERC decision involving National Grid, FERC ruled in favor of having Alliance Companies join the Midwest ISO and reiterated its prudence standard. In this order FERC argues that prudence is evaluated using the "reasonable man" standard, which means that "the prudence of an action is

[17] *See City of New Orleans vs. Entergy Corporation, et. al.*, 61 FERC ¶ 63,007 (1992) at 65,006.

determined by examining the decision-making process at the time the decision was made."[18]

Q. Can you point to a State precedent?

A. Yes. This definition of prudence is also reflected, for example, in a ruling on prudence by the Louisiana Supreme Court in *Gulf States Utilities Company v. Louisiana Public Service Commission.*

> "Although there is no single formulation sufficient to express constitutional, statutory, or judicially derived standards for determining how much of a utility's investment in a particular plant should be included within its rate base . . . one of the principles used by ratemaking bodies and courts to make such a determination is the prudent investment standard....That is, the utility must demonstrate that it 'went through a reasonable decision making process to arrive at a course of action and, given the facts as they were or should have been known at the time, responded in a reasonable manner.'....the focus in a prudence inquiry is not whether a decision produced a favorable or unfavorable result, but rather, whether the process leading to the decision was a logical one, and whether the utility company reasonably relied on information and planning techniques known or knowable at the time."[19] [In-text Citations Omitted]

Q. Has APS shown that it used reasonable decision-making based on known or knowable facts?

A. No. Two known facts at the time APS negotiated the Affiliate PPA are especially important. First, since 1996, six years ago, APS knew the Commission wanted to move toward competition to gain benefits for

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[18] *See National Grid USA et. al.*, 97 FERC ¶ 61,329 (2001) at page 14.
[19] *See Gulf States Utilities Company vs. Louisiana Public Service Commission*, 578 So. 2d 71 (1991) at page 10.

consumers.[20] Second, for at least that long, APS had to know that competitive power suppliers are willing to build new power plants to serve Arizona. For both these reasons, to prove the prudence of its decision to accept its Affiliate PPA, APS must show its decision-making involved a comparison to market alternatives. APS offers no evidence that it considered even one market alternative let alone the full range of such alternatives known to exist at the time of its decision. By this procedural failure alone, APS clearly has failed to show prudence.

Q. What would APS have to do to demonstrate prudence?

A. To demonstrate the prudence of its decision on the APS Affiliate PPA, APS would have to conduct an RFP, or negotiate in good faith on bilateral contracts. I see no alternative given the facts known today. That is, APS could establish prudence if, and only if, it complied with the Commission's requirement for competitive procurement in the first place.

B. APS chose to use FERC's benchmark test to justify its Affiliate PPA, but APS fails that test from the start because it failed to assure comparability of service between its Affiliate PPA and the benchmark PPAs.

[20] The Commission itself emphasized benefits from competition in Decision No. 60977, "[i]n the long-run, it is believed that competition will result in lower prices, better service, more choices and increased innovation." (Decision No. 60977 at page 5)

1. FERC established its three tests in 1991 in an Order rejecting Boston Edison Company's Affiliate deal with Edgar Electric Energy Company, and implemented these tests when approving the Ocean State Power II Affiliate deal in 1992.

Q. Will FERC also have to approve the APS Affiliate PPA?

A. Yes, because it is a wholesale contract. But, in any event, APS chose FERC's benchmark test to present to the Commission, so it is useful for the Commission to be aware of the FERC approach.

Q. Are there specific case precedents in which FERC developed its approach to approving Affiliate PPAs?

A. Yes. In *Boston Edison Company Re: Edgar Electric Energy Company* 55 FERC ¶ 61,382 (1991) ("Edgar"), FERC established its standards for approving market-based transactions between an affiliated buyer and seller. In *Ocean State Power II* 59 FERC ¶ 61,360 (1992), *reh'g denied* 59 FERC ¶ 61,146 (1994) ("Ocean State II"), FERC implemented the standards set forth in *Edgar*.

Q. Would you please describe the outcome of the Boston Edison case?

A. Yes. Edgar Electric Energy Company is a subsidiary of Boston Edison. On January 31, 1991, Boston Edison filed on behalf of Edgar Electric for the approval of a 20-year contract for capacity and energy. FERC ultimately denied its request stating among other things that Boston Edison "failed to demonstrate that the proposed contract between it and its affiliate, Edgar, does not provide the parties with the chance for abuse of self-dealing. . ."[21]

As stated in the order, FERC's authority for rejecting the contract stems from the Federal Power Act (FPA): "[m]arket-based rates for sales involving affiliates will be found to violate section 205(a) of the FPA unless there is a clear showing of lack of potential affiliate abuse."[22] Thus, when self-dealing is a critical issue, "the Commission [FERC] must ensure that the buyer has chosen the lowest cost supplier from among the options presented, taking into account both price and non-price terms (i.e., that it has not preferred its affiliated without justification)."[23]

Q. Did FERC define how an applicant could prove affiliate abuse is not a concern?

A. Yes. To mitigate these concerns about affiliate abuse, FERC stated that, in the past, it has relied on a market-value test, and in this order, provides three examples of how a market-value test may be applied.

First, Boston Edison could have offered evidence of, "direct head-to-head competition between Edgar and competing unaffiliated suppliers either in a formal solicitation or in an informal negotiation process."[24] However, when an application offers this kind of evidence, the applicant must demonstrate that: (1)

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[21] *See Boston Edison Company Re: Edgar Electric Energy Company* 59 FERC ¶ 61,382 (1991) at page 19.
[22] *Id.*, at page 13.
[23] *Id.*, at page 5.

the solicitation or negotiation process did not favor the affiliate; (2) the analysis of the bids or responses did not favor the affiliate; and (3) the affiliate was chosen "based on a reasonable combination of price and non-price factors."[25] Further, if the affiliate is chosen and is *not* the least cost option, the applicant must explain why that selection was made.

Second, Boston Edison could have offered evidence of, "the prices which nonaffiliated buyers were willing to pay for similar services from the Edgar project."[26] However, FERC notes that this evidence, "is only credible to the extent that the non-affiliated buyers are in the relevant market as the purchaser, and are not subject to market power by the seller or its affiliates."[27]

Third, Boston Edison could have offered benchmark evidence, "which shows the prices, and terms and conditions of sales made by nonaffiliated sellers. This evidence could include purchases made by Boston Edison itself, or by other buyers in the relevant market."[28] Again, FERC states this type of evidence is only reliable to the extent that the benchmark sales are "contemporaneous and whether they are for similar services when compared to the instant transaction."[29]

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[24] *Id.*, at page 16.
[25] *Id.*
[26] *Id..*, at page 16.
[27] *Id,*. at page 16-17.
[28] *Id,*. at page 17.

Q. Which test did Boston Edison fail?

A. Boston Edison failed the third test even though it submitted benchmark data. It failed for three reasons. First, the methods and assumptions Boston Edison used to calculate the levelized price of each alternative were not documented. In addition, Boston Edison did not explain the criteria it used to evaluate price and non-price factors in one group of the benchmark data.

Second, the benchmark data was not for the same services as those contained in the Edgar contract. FERC Staff was not convinced that that QFs in the benchmark evidence would compete with Edgar in the same market nor was it convinced that Boston Edison considered non-price dissimilarities (dispatch and contract term) in comparing Edgar to the benchmark evidence. "When benchmark evidence is used to validate market-based prices, dissimilarities in non-price terms must be taken into account so that the price comparisons are meaningful."[30]

Third, FERC Staff noted that Boston Edison failed to include projects with offers that were contemporaneous with the Edgar project.

Q. Please describe the outcome of *Ocean State II*.

A. Ocean State II is a 250-MW plant owned by partnership in which affiliates of New England Power, Montaup, and Newport have equity shares. On August 1,

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[29] *Id.*

1991, Ocean State II filed rate schedules for approval by FERC. To prove that the Ocean State II transaction lacked the potential for affiliate abuse, Ocean State II submitted a market-value test in the form of benchmark evidence, as set forth in *Edgar*. Recall in *Edgar*, that when the applicant submits benchmark sales as evidence, the evidence must be contemporaneous with, and for similar services when compared to the instant transaction. Also, the "benchmark analysis should examine non price as well as price terms, and assumptions used in comparing the various projects should be explained with respect to both price and non price terms. Finally, the applicant must demonstrate to the Commission's [FERC's] satisfaction that the benchmark evidence was not distorted by exercise of market power by the seller or its affiliate."[31]

FERC accepted Ocean State II's benchmark evidence as proof that Ocean State II and its affiliates lack market power and affiliate abuse. That is, FERC accepted Ocean State's: (1) definition of the relevant market; (2) comparison of contemporaneous transactions; (3) comparability of services; and (4) benchmark data. Ocean State II compared non-price terms of the alternatives that it viewed as important: (1) developmental assurance; (2) dispatchability; (3) flexibility of maintenance scheduling; (4) operations oversight; (5) availability penalties; (6) protection against project failure; (7) fuel type; (8) contract term; and (9) price after contract expiration.

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[30] *Id.*, at page 2 of Appendix.

2. More recent FERC cases involving Affiliate deals rely even more heavily on RFPs as a test.

Q. Are there even more recent FERC decisions?

A. Since *Edgar* and *Ocean State*, numerous applicants have sought to apply the standards set forth in those cases in order to gain the FERC's approval of market-based transactions between affiliates. In the more recent cases, applicants and FERC have relied more heavily on RFPs as the test.

Q. Can you provide a few examples?

A. Yes. The first example involves Aquila, an affiliate of UtiliCorp. On March 23, 1999, Utilicorp and Aquila filed jointly with the FERC a Power Sales Agreement (PSA) for capacity and energy sales of 135 MW at market-based rates to UtiliCorp.[32] The Commission approved this transaction on May 27, 1999.

Q. Did Aquila rely on an RFP?

A. Yes. In meeting FERC's standards, Aquila relied upon the use of an RFP and benchmark evidence. This case was important because it was the first time an applicant relied upon the bidding process as set forth in *Edgar*. Several features of the bid evaluation criteria are worth noting: (1) buyout feature; (2) fixed capacity price; (3) a "guarantee [of] the availability of capacity and energy, with

[31] *See Ocean State Power II* 59 FERC ¶ 61,360 (1992) at page 13.

reductions in capacity payments for failure to meet the guaranteed levels;"[33] and (4) a contract term of four years or less. Note that an independent consulting firm conducted the initial analysis of the bids and concluded that only Aquila met each of the RFP's non-price terms and conditions.

Q. Did Aquila also present benchmark data?

A. Yes. For its benchmark evidence, Aquila provided contemporaneous prices quoted by energy brokers for the period of its transaction, which showed that the prices in the PSA were no higher than the quoted prices.

Q. What is your second example?

A. The second example involves MEP Pleasant Hill, LCC ("MEP"), a 600-MW generating plant that is an affiliate of UtiliCorp. On May 6, 1999, MEP and UtiliCorp filed with FERC a Unit Power Sales ("UPS") Agreement for capacity and energy at market-based rates. FERC approved the UPS on July 2, 1999.

Q. Did MEP rely on an RFP?

A. Yes. In meeting FERC's standards, MEP relied upon the use of an RFP to demonstrate that the rates in the UPS agreement were "no higher than the price UtiliCorp would have paid to purchase power from a nonaffiliate and that the process which resulted in the UPS Agreement satisfies the requirements set forth

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[32] *See Aquila Energy Marketing Corp.* 87 FERC ¶ 61,217 (1999).
[33] *Id.*, at page 4.

in *Edgar*."[34] The criteria used to evaluate bids were similar to the Aquila case: (1) buyout feature; (2) fixed capacity price; (3) fixed price performance guarantee; and (4) a contract term of four years or less.

Q. Did MEP also have a third party evaluator?

A. Yes. In the final phase of the bidding, an independent energy consulting firm concluded that MEP was the only bidder that fulfilled the bidding criteria established by UtiliCorp, and that the total costs of MEP's proposal, "were consistently more favorable than Houston's [2nd place bidder] in all scenarios but one case; and in that one case the costs were virtually the same."[35]

Q. What is your third example?

A. My third example involves Ameren Energy Marketing Company ("AEM"), an affiliate of Ameren Union Electric Company ("AmerenUE"). On April 17, 2001, AEM filed with FERC a Power Sales Agreement ("PSA") that provided up to 450 MW of firm capacity and energy for the contract term to AmerenUE.[36]

Q. Did AEM rely on an RFP?

A. Yes. In meeting FERC's standards, AEM relied upon the use of an RFP and a benchmark analysis. The RFP was designed as a two-stage process, in which

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[34] *See MEP Pleasant Hill, LLC* 88 FERC ¶ 61,027 (1999) at page 3.
[35] *Id.*
[36] *See Ameren Energy Marketing Company* 95 FERC ¶ 61,397 (2001).

the bidders short-listed from the first stage would then arrange for firm transmission service and network transmission service. This was important because the awarding of the contract was contingent upon the approval of firm transmission delivery to the Ameren system and of network transmission delivery within the Ameren system. According to the Commission's order, the RFP only considered fixed-price capacity offers.

Q. How was the benchmark analysis done?

A. Once AmerenUE determined AEM to be the winner, it conducted a benchmark analysis to evaluate the reasonableness of the PSA. The benchmark analysis consisted of comparing AEM's energy price to market prices and comparing all the energy bids received to pricing information for contracts during the same period at EnronOnline. For capacity bids, no comparison of capacity prices was made. However, AEM offered evidence of existing contracts with a non-affiliate as proof of non-affiliate abuse and further evidence that the capacity prices in negotiations with non-affiliates for contracts during the same time period, "entailed price levels higher than those in the PSA."[37]

Q. Did FERC approve the AEM affiliate deal?

A. Yes. The Commission conditionally accepted the PSA on June 14, 2000. One of the conditions for acceptance of the PSA was that AEM file a revised PSA,

[37] *Id.*, at page 7.

which specified the market index that would determine the non-fixed energy price.

3. Dr. Hieronymus failed to adjust for the fact that the benchmark contracts generally have superior non-price features.

Q. Why do you raise earlier in your Testimony the concern that the product in the benchmark contracts used by APS is not comparable to that in the APS Affiliate PPA?

A. This is a concern because FERC's requirements for a benchmark comparison, based on its *Edgar* and *Ocean State II* orders, are that the benchmark must involve services comparable to those offered in the affiliate PPA transaction being evaluated.

In general, the benchmark contracts used by Dr. Hieronymus do not meet this requirement for comparable service since they provide service superior to that in the APS Affiliate PPA. As explained previously, the reason is that the terms of the APS Affiliate PPA provide insufficient price stability and reliability guarantees.

Q. How do Mr. Meehan's benchmark contracts compare in terms of fixed cost and capital cost risk?

A. In general, there are fixed formula capacity prices stated in $/kw-month that are set for the entire term of the PPA. For example, PacifiCorp provides for a fixed capacity payment, and inflation indexing of the fixed O&M price based on the Consumer Price Index ("CPI"). (Exhibit No.__(CRR-5)) For some other CA DWR PPAs, capacity is priced on a variable basis ($/kwh), but that capacity price is also fixed due to the must-take nature of the contracts. In contrast, the APS Affiliate PPA allows a pass-through of any capacity costs. Therefore, capacity price risk for ratepayers under the APS Affiliate PPA is higher than and, therefore, inferior to that of the benchmark.

Q. How do the benchmark contracts compare in terms of fuel cost risk?

A. In general, the benchmark contracts provide for fuel costs tied to guaranteed heat rates and specific fuel price indices. For example, the fuel costs under the Sempra contract are based on either 7,500 btu/kwh for baseload service or 10,000 btu/kwh for peaking service. (Exhibit No.__(CRR-6)) These fixed heat rates are multiplied by the Southern California Border Gas Price for the billing period. This type of calculation is explicit, measurable, and easily verified by both parties. In contrast, the APS Affiliate PPA allows a pass-through of any fuel costs. Therefore, the fuel price risk for ratepayers under the APS Affiliate PPA is higher than and, therefore, inferior to that of the CA DWR PPAs.

Q. How do the benchmark contracts compare in terms of reliability performance guarantees?

A. In general, the benchmark contracts provide for specific reliability guarantees. Not all of these are ideal. For example, the PacifiCorp contract excuses both forced and scheduled outages up to 12% of the time. Still, as compared to the APS Affiliate PPA with no reliability guarantees, even this is a better deal for ratepayers.

Q. How do the benchmark contracts compare on PPA length?

A. Mr. Meehan's benchmark contracts generally have contract terms of ten to twelve years. APS requires Arizona ratepayers to lock into a cost-plus deal for 29 years. The longer term may make the APS Affiliate PPA cost-plus deal less flexible and, therefore, inferior to the CA DWR PPAs.

Q. Do you have other compatibility concerns with Dr. Hieronymus' testimony?

A. Yes. Dr. Hieronymus' assertion that capacity and energy that would be purchased from the market by PWCC is irrelevant to his analysis has the potential to be extremely misleading. Under the terms of the APS Affiliate PPA, it appears that PWCC has the authority to purchase power from the market to meet APS' energy requirements. In the past, the acquisition of purchased power by APS to meet its own energy requirements has been a significant portion of its overall power supply. As an example, APS acquired approximately 32% of its total energy from the market in 2000.[38] Dr. Hieronymus' failure to address this issue is a significant shortcoming of his analysis. My concern is that by out-sourcing all purchases to PWCC, an affiliate, APS is institutionalizing self-dealing.

C. A variance is contrary to the letter and the spirit of the Electric Competition Rules.

Q. Is the APS request for a variance consistent with Arizona Commission policy on competition?

A. No. It is clear that, since the Electric Competition Rules were established in 1996, the goal of the Commission has been to make the transition to competition, which the Commission saw as affording ratepayers several long-term benefits. In Decision No. 59943 (December 26, 1996), the Commission proposed the Rules to "set forth a framework for the inevitable transition from a non-competitive to a competitive environment."[39] The benefits of competition were stated in Decision No. 60977 (June 22, 1998). In its introduction, the Commission stated, "[i]n the long-run, it is believed that competition will result in lower prices, better service, more choices and increased innovation."[40]

Q. Did the Commission find that its competition rules were in the public interest?

A. Yes. In its 1998 Emergency Rules, the Commission emphasized the importance of these Rules for the public interest. In Decision No. 61071 (August 10, 1998)

[38] *See* Arizona Public Service Company FERC Form No. 1 at page 401a.
[39] *See* Decision And Amended Rules on Electric Competition, Docket No. U-0000-94-165, Decision No. 59943.

it stated that the "safe, efficient, and reliable provision of electric service is clothed with the public interest, and the details resolved by the proposed rules further those interests."[41] One proposed rule, which furthered those interests, was the adoption of the competitive bid requirement which required that all power purchased (except purchases made through the spot market) to serve Standard Offer Customers be obtained through a competitive bid. In Decision No. 61969 (September 29, 1999) the Commission changed 1606(B) to its present form.

> "After January 1, 2001, power purchased by an investor owned Utility Distribution Company for Standard Offer Service shall be acquired from the competitive market through prudent, arm's-length transactions, and with at least fifty percent through a competitive bid process."[42]

Q. Has the Commission told APS it must comply with the Rules?

A. Yes. In 1999, the Commission specifically directed APS to comply with these Rules and stated explicitly that it should procure generation from the competitive market. The Settlement Agreement directs APS that, when obtaining power for Standard Offer customers, it must act in accordance with the Electric Competition Rules. More explicitly, in the Addendum to the Settlement Agreement (November 24, 1999), the Commission stated that:

> "[a]fter 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."[43]

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[40] *See* Decision No. 60977 at page 5.
[41] *See* Decision No. 61071 at page 2.
[42] *See* Decision No. 61969 at Appendix A page 15.
[43] Addendum to the Settlement Agreement (November 24, 1999) at page 3.

Q. Do the Rules allow for a variance?

A. Yes, and the Commission granted APS a two-year extension so that it could comply with these Rules; now, only three years later, APS is now asking for an exemption from the Rules, which would allow it to permanently bypass the competitive bid requirement through a PPA with a 29-year term.

This variance request is clearly not in accord with the spirit or the letter of the Commission policy or precedents. The Rules and the 1999 APS Settlement Agreement clearly mandate that power purchased to serve Standard Offer customers be competitively procured. Instead, APS is applying to circumvent these Rules with a PPA that it cannot prove to be in the public interest.

Q. The variance and the APS Affiliate PPA contrary to the Electric Competition Rules?

A. Yes. The APS request for a variance and for acceptance of the PPA would mark a retreat from the Commission's effort started six years ago to move Arizona to a competitive power generation business; in this way the request is contrary to the Rules.

Q. Does APS offer any reasons to motivate this retreat?

A. Yes. APS tries to motivate the retreat by pointing to the California crisis, but that does not justify such a retreat. The California crisis was caused primarily by well-intentioned, but ultimately misguided market rules adopted in that State, and by adverse market conditions. With respect to market rules: (a) utilities were required to buy all supply in a volatile spot market, and (b) at the same time, sell to retail customers at a fixed price. It was inevitable that the buy and sell prices would get out of sync and cause credit problems. With respect to market conditions, the central problem was a shortage of power plant capacity that was exacerbated by the fact that suppliers were not getting paid.

Q. Is such a crisis likely in Arizona?

A. No. Clearly, Arizona has not, and need not, adopt these misguided market rules. And, unless the development of competitive power supplies is stifled, there is no need to suffer a capacity shortage.

Indeed, APS reports that, to its credit, it took actions that insulated Arizona from the California crisis. It is unfortunate that, having blocked the spread of the crisis to the state, APS is now using that crisis to justify abandoning the move to competition for wholesale generation. In short, nothing has changed since the Rules were adopted to suggest that reliance on a competitive wholesale market is no longer in the public interest.

Q. You said APS is asking the Commission to retreat from competition. Do you see this as a retreat to traditional cost-plus regulation?

A. No. It is important to see that the APS Affiliate PPA may even be a worse deal for Arizona ratepayers than traditional regulation. The APS Affiliate PPA gives

APS all the benefits of a cost-plus deal, but appears to whittle away any advantage of such a deal for ratepayers. I have questions about several elements of the APS Affiliate PPA in this regard.

Q. Would you give a few examples of your questions?

A. Yes. For example, the APS Affiliate PPA gives PWCC the right to procure from new power plants. Would approval of the APS Affiliate PPA be tantamount to the Commission ruling once and for all on the prudence of all new generation and all new purchases used by PWCC to supply Standard Offer customers? If not, how does traditional prudence review fit into the APS Affiliate PPA context?

Similarly, the APS Affiliate PPA includes as a Force Majeure event, "material failure of performance by any PWCC supplier."[44] Does this mean that any performance failure by PWEC is excused? Does this mean that a turbine failure due to poor maintenance is excused? Does this mean fuel supply problems are excused? Again, this Force Majeure clause is clearly inferior to that obtainable in the competitive marketplace. But the Commission should also worry that it cuts away at even the Commission's most basic rights for disallowances to be considered under traditional regulation.

[44] Power Purchase Agreement between Pinnacle West Capital Corporation and Arizona Public Service Company, Exhibit A at page 30.

Also, in this context, why does APS get a fixed rate of return, reflecting an 11.25% return on equity and a 7.5% interest rate, that it would not otherwise enjoy under traditional cost-plus ratemaking? And why does APS keep 75% of the profit from off-system sales when it would keep much less (perhaps none) of those profits under traditional cost-plus ratemaking?

D. Approval of the variance and the APS Affiliate PPA would signal competitive power suppliers and their investors that the door has been closed on fair opportunities to offer wholesale power in Arizona.

Q. Has APS opined on whether approval of the variance and APS Affiliate PPA would harm Arizona's transition to competition?

A. Yes. APS claims approving the variance and the APS Affiliate PPA will do no harm to competition, and make no difference in market prices.

Q. Do you agree?

A. No. Granting the variance and approving the APS Affiliate PPA will most certainly do harm to competition and, thereby, make a difference in market prices. The findings APS asks the Commission to make are so unreasonable that such approval will certainly send a signal to competitive power suppliers and their investors that the door has been closed on opportunities in Arizona.

Q. What do you mean unreasonable findings?

A. For example, APS wants the Commission to conclude that there are no competitive alternatives worthy of evaluation. This despite the fact that RFPs routinely bring forth abundant bids.

Q. Can you provide examples of recent RFPs in the West?

A. Yes. In 1999, Public Service Company of Colorado ("PSCO")[45] released its *Integrated Resource Plan* ("Plan") which detailed the required generating capacity for its territory. As part of the Plan, an RFP was issued in January 2000 for 1,030 to 1,365 MW and a term length of up to ten years. PSCO received 50 bids totaling 9,000 MW in response. PSCO accepted bids from twelve facilities totaling 1,995 MW, 46% more megawatts than it had originally sought.

Q. Did anyone argue that utility-built plants would be a better alternative than this competitively procured power?

A. Yes. During the solicitation process, the Colorado Office of Consumer Counsel intervened and filed a complaint with Colorado Public Utilities Commission ("PUC") stating that the estimated construction cost was millions more than what PSCO would pay to build the plant themselves. The PUC ruled in favor of PSCO.

Q. Is PSCO anticipating another RFP?

A. Yes. Xcel Energy is currently working on its 2002 Integrated Resource Plan and, if needed, will issue an RFP in 2003.

Q. Do you have other examples of RFPs?

A. Yes. Sierra Pacific Power and Nevada Power each issued an RFP for renewable energy. Sierra Pacific Power received a total of 30 proposals from 23 bidders totaling 2,449 MW. Nevada Power received 19 proposals from 15 bidders totaling 1,845 MW.

In addition, in August 2001, the Arizona Electric Power Cooperative issued an RFP for 50-80 MW in 2003 and up to 130 MW in 2010. I understand proposals are now being considered for negotiation.

Q. Are you aware of other, more recent competitive negotiations in the West?

A. Yes. Nevada Power just announced two long-term agreements on March 22, 2002 which it believes could reduce a requested rate increase of over 20% to 8.8%. These two agreements are with competitive power suppliers, Williams Energy and Reliant Energy.[46] Indeed, on March 25, 2002, Williams announced it had entered into exclusive negotiations with Nevada Power on a broader arrangement involving fuel supply, new assets, and risk management.[47]

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[45] Xcel Energy now owns the Public Service Company of Colorado.

[46] News Release, *Nevada Power Company Reaches Agreements for Long-Term Power* (March 22, 2002).

Q. Why is an RFP or good faith competitive negotiation important?

A. They are important because, without them, the claim that competitive offers are scarce can become a self-fulfilling prophecy. That is, an RFP or good faith negotiations gives notice of a need for power as well as notice that there will at least be some chance of an apples-to-apples comparison to the local utility proposal. Without an RFP, or an opportunity for a fair competitive negotiation, competitive power suppliers may see no reason to incur additional costs of project development, and will not pursue new projects in Arizona because they see no fair opportunity to compete.

Q. How long does an RFP process take?

A. If time is not a constraint, I have recommended about 180 days. If time is a constraint, the process can be shortened.

Q. Do you have an example of a shorter process?

A. Yes. The Arizona Commission is not the first to face a utility trying to side step a requirement for competitive procurement because time was said to be short. In 1998, Virginia Power asked for regulatory approval for the construction of five new gas-fired turbines of 150 MW each and asked for an exemption from the Virginia State Corporation Commission's bidding requirement due to a "critical need" for capacity in 2000 and 2001. Nonetheless, the Virginia Commission ordered Virginia Power to issue an RFP with the oversight of the

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[47] News Release, *Williams, MidAmerican and Nevada Power Negotiate First Risk Management Contract*

Virginia Commission Staff and cited a previous order in which it ruled that, "bidding programs continue to provide electric utilities with an excellent option for acquiring necessary capacity in an orderly and reasonable manner."[48]

The timetable for Virginia Power's RFP was compressed significantly because of time constraints. The Virginia Commission issued its order on January 14, 1999, and a draft RFP was required five days later. Only two days were set for the Staff's review. Bids were due by March 26, 1999. The online date for the capacity was July 2000.[49]

Ultimately, the Virginia Commission determined Virginia Power's proposal provided "the best price to supply the necessary capacity in a timely and reliable manner."[50] The entire process took just 78 days, from the day the Virginia Commission issued its order on January 14, 1999 requiring the RFP, to the completion of the Virginia Commission Staff's review of the bids on April 2, 1999.

Q. Did the Virginia Commission continue to require RFPs?

A. Yes. The Virginia Commission, citing concerns over Virginia Power's market power, directed Virginia Power to continue to use competitive bidding to secure

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for Regulated Utility (March 25, 2002).

[48] *See* Case No PUE980462 (January 14, 1999) at page 5.

[49] *See* Case No PUE980462 (January 14, 1999) at page 17.

[50] *See* Case No. PUE980462 (May 14, 1999) at page 8.

its remaining capacity requirements in the future.[51] The Virginia Commission directed Virginia Power, "to take promptly all steps necessary to secure market supplied capacity for delivery in 2001 and 2002."[52]

Q. Has APS elsewhere estimated the range and number of competitors it faces?

A. Yes. When securing market-based rate authority from FERC, APS' market power study claimed it faced competition from throughout the Western U.S. APS claims the market included 70,000 MW of competitors and that it controlled only a small share (about 5%) of the market.

Q. What relevance does the APS market power study have here?

A. The APS market power study reveals one more unreasonable finding APS is asking the Commission to accept. Recall that the APS Affiliate PPA will be implemented under PWCC's market-based rate authority. To grant the variance and approve the APS Affiliate PPA, APS will ask FERC to find that APS faces no viable competition. But, then, APS asks the Commission to allow it to sell under market-based rate authority; an authority that would never have been granted had APS truly not faced viable competition. APS simply cannot have it both ways.

Q. How do you know APS is asking for market-based rates?

[51] *See* Case No. PUE980462 (May 14, 1999) at page 6.
[52] *See* Case No. PUE980462 (May 14, 1999) at page 6.

A. I know APS is asking for market-based rates because the APS Affiliate PPA is made subject to the PWCC market-based rate authorizations. At Section 1.1 (B) the APS Affiliate PPA states "APS shall pay PWCC for the sales in Section 1.1(A) as provided in the attached Service Schedule and in accordance with PWCC's Tariff." In Exhibit A page 32, "Tariff" is defined as "PWCC's Market-Based Rate Tariff." APS is not here asking for cost-based rates.

Q. Is APS' position unreasonable in other respects?

A. Yes. It is unreasonable to ask the Commission to find that, if competitive power suppliers cannot fully fill its Standard Offer needs in 2003, it is an appropriate response to lock in to a 29-year PPA. Clearly, it is overkill to ask for a 29-year variance as APS has done. The obvious response is to issue an RFP, and enter good faith negotiations now, but to stagger the on-line dates of the winning bidders to give the market more time to respond.

Q. Why do you refer to a 29-year variance?

A. I refer to a 29-year variance because I view the APS Affiliate PPA as a 29-year contract. The original term of the APS Affiliate PPA is from 2002 through 2015. However, the APS Affiliate PPA states "[t]his agreement shall automatically be renewed for up to three additional 5-year terms unless either Party provides to the other Party a notice of termination at least 12 months prior to the scheduled termination of this Agreement."[53] Since the 15-year extension is fully in the hands of two affiliates, and the contract is cost-plus, I see no reason to expect it to be terminated. Surely, there is no reason to assume that the Affiliate PPA will not be extended and to base assess the merit of the PPA over its limited initial term.

Q. Has APS taken any other unreasonable positions?

A. Yes. The Commission would have to accept APS' claim that the variance will do nothing to change aggregate power demand and supply in 2003 so it cannot affect competition, or the competitive market price. Everyone who took Econ 101 can agree that if the supply and demand curves do not shift, the market price will remain the same. However, APS ignores the fact that, if it can just preempt competition, supply and prices are most certainly affected.

Moreover, why is 2003 the only year to assess? If the approvals for the variance are granted, competitive power suppliers and their investors will see Arizona as inhospitable to private investment and that will most certainly affect supply in future years. After all, encouraging private investment was one motive for the Commission to issue the Rules in the first place.

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[53] Purchase Power Agreement between Pinnacle West Capital Corporation and Arizona Public Service Company at page 21, Section 11.2(B).

V. RECOMMENDATIONS TO THE COMMISSION

Q. Do you have any recommendations for the Commission?

A. Yes. Based on my Testimony, I recommend that the Commission do the following:

1. Deny both the request for a variance and for approval of the APS Affiliate PPA.
2. Order APS to maintain responsibility for power purchases and dispatch, and not outsource that responsibility to PWCC.
3. Set payments for all present and formerly-owned APS generation equal to that based on traditional cost-plus rate making, until APS conducts competitive procurement for all its Standard Offer needs and APS generation is selected through that procurement.
4. Order APS to competitively procure, through competitive bids and negotiated contracts, all its Standard Offer capacity and energy needs. The goal will be to get the best deal for ratepayers in terms of price, risk, reliability, and environmental performance.
5. For the competitive bids, APS should issue RFPs, with: (a) a draft RFP to be prepared by APS within 15 days after the Order; (b) Third-Party Evaluator and Intervenor review completed in 30 days after the Order; (c) the RFP issued in 40 days after the Order; and (d) bids due 75 days after the Order. This schedule will not materially prejudice APS, but it will enable

the Commission to base its decision on *facts* about the extent of wholesale competition rather than on APS' assertions.

6. The on-line dates of winning bidders should be staggered to get the best deal for ratepayers. Bids that offer the best deal to ratepayers and can be on-line in 2003 should be winners. Bids that offer the best deal to ratepayers, but cannot be on-line until later (2004, 2005, etc.) should be winners too; that is, their later on-line dates should be allowed. The on-line dates would dictate the priority for executing final contracts. Length of contracts should also be varied in the context of a risk management plan.
7. PWCC should be required to bid each of its facilities separately into the RFP. Each of PWCC's bids will be evaluated on the same terms as all other bids and, if it wins, PWCC will be held to its bid, as would any bidder.
8. Since PWCC is a bidder, the Commission should insist on pre-approving a Third Party Evaluator to serve along with the Commission Staff and APS on the Bid Evaluation Team.
9. If the Commission believes that *non-gas-fired resources* must be included in the portfolio that serves Standard Offer customers, then APS will issue an RFP with a portion set aside for non-gas-fired power. The on-line dates may be staggered to accommodate longer lead times.

Q. Does this conclude your testimony?

A. Yes.

EXHIBIT CRR-1

Exhibit No.__(CRR-1)

LIST OF TESTIMONY AND OTHER PUBLICATIONS FOR CRAIG R. ROACH, Ph.D.

BOSTON PACIFIC COMPANY, INC.

CRAIG R. ROACH

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Coal Use by Industry and the Associated Air Pollution Emissions in the Period From 1980 to 2000 Under Alternative Market and Regulatory Conditions. Madison, WI: University of Wisconsin.

EXHIBIT CRR-2

Exhibit No. ___ (CRR-2)

CORRECTED HIERONYMUS EXHIBIT WHH-3:
LEVELIZED COST OF DEDICATED UNITS

Corrected Hieronymous Exhibit WHH-3: Levelized Cost of the Dedicated Units

	a	b	c	d	e	f	g
Year	MWh	Fuel Cost	Capital Cost	Fuel + Capital Cost	Nominal Cost/MWh	Ancillary Services Cost	Nominal Cost/MWh w/ Anc. Serv.
2003	21,090,000	$ 366,966,000	$ 763,200,000	$ 1,130,166,000	$ 53.59	$ 52,725,000	$ 56.09
2004	21,090,000	$ 374,832,191	$ 805,440,000	$ 1,180,272,191	$ 55.96	$ 52,725,000	$ 58.46
2005	21,090,000	$ 387,165,022	$ 821,548,800	$ 1,208,713,822	$ 57.31	$ 52,725,000	$ 59.81
2006	21,090,000	$ 400,341,589	$ 839,622,874	$ 1,239,964,462	$ 58.79	$ 52,725,000	$ 61.29
2007	21,090,000	$ 409,359,644	$ 859,773,823	$ 1,269,133,467	$ 60.18	$ 52,725,000	$ 62.68
2008	21,090,000	$ 419,063,009	$ 882,127,942	$ 1,301,190,951	$ 61.70	$ 52,725,000	$ 64.20
2009	21,090,000	$ 429,969,911	$ 906,827,524	$ 1,336,797,436	$ 63.39	$ 52,725,000	$ 65.89
2010	21,090,000	$ 441,413,534	$ 934,939,178	$ 1,376,352,711	$ 65.26	$ 52,725,000	$ 67.76
2011	21,090,000	$ 454,507,621	$ 963,922,292	$ 1,418,429,913	$ 67.26	$ 52,725,000	$ 69.76
2012	21,090,000	$ 468,935,485	$ 993,803,883	$ 1,462,739,368	$ 69.36	$ 52,725,000	$ 71.86
2013	21,090,000	$ 483,547,455	$ 1,024,611,804	$ 1,508,159,258	$ 71.51	$ 52,725,000	$ 74.01
2014	21,090,000	$ 498,910,293	$ 1,056,374,769	$ 1,555,285,063	$ 73.75	$ 52,725,000	$ 76.25
2015	21,090,000	$ 513,670,895	$ 1,089,122,387	$ 1,602,793,283	$ 76.00	$ 52,725,000	$ 78.50
			NPV	$ 9,795,935,776	$ 464.48	$ 394,747,009	$ 483.20
			Lev. Nom.		$ 62.04		$ 64.54

	h	i	j	k	l	m	n	o	p
		Real Fuel Costs			Real Fuel Esc. Indices				Change in Total Fuel
Year	Inflation	Gas	Coal	Nuclear	Gas	Coal	Nuclear	Total Fuel	
2003		3.20	19.37	0.60	1.0000	1.0000	1.0000	1.0000	
2004	1.018	3.24	19.37	0.60	1.0125	1.0000	1.0000	1.0034	1.0214
2005	1.020	3.34	19.56	0.60	1.0309	1.0098	1.0000	1.0126	1.0329
2006	1.022	3.43	19.76	0.60	1.0269	1.0102	1.0000	1.0118	1.0340
2007	1.024	3.44	19.66	0.60	1.0029	0.9949	1.0000	0.9986	1.0225
2008	1.026	3.44	19.56	0.60	1.0000	0.9949	1.0000	0.9978	1.0237
2009	1.028	3.47	19.37	0.60	1.0087	0.9903	1.0000	0.9981	1.0260
2010	1.031	3.50	19.08	0.60	1.0086	0.9850	1.0000	0.9957	1.0266
2011	1.031	3.54	18.89	0.60	1.0114	0.9900	1.0000	0.9987	1.0297
2012	1.031	3.58	18.79	0.60	1.0113	0.9947	1.0000	1.0007	1.0317
2013	1.031	3.61	18.70	0.60	1.0084	0.9952	1.0000	1.0002	1.0312
2014	1.031	3.62	18.70	0.60	1.0028	1.0000	1.0000	1.0007	1.0318
2015	1.031	3.63	18.61	0.60	1.0028	0.9952	1.0000	0.9986	1.0296

Sources: Please see attached

Exhibit No.__(CRR-2)

Sources for each column:

(a) Affiliate PPA, Service Schedule, Section 3.2.3.2.
(b) Affiliate PPA, Service Schedule, Section 3.2.2.3 for 2003 Base Fuel Charge of 17.40/MWh in 2003. Thereafter, escalated with column (p).
(c) Affiliate PPA, Service Schedule, Section 3.2.2.1 for 2003 and 2004. Thereafter escalated with inflation as in column (h).
(d) Sum of (b) and (c).
(e) (d) divided by (a). NPV and levelized nominal price ("Lev. Nom") for all 13 years calculated by Excel with 9% discount rate prescribed by Dr. Hieronymus.
(f) \$2.50/MWh from Direct Testimony and Exhibits, Eugene T. Meehan, FERC Docket No. ER02-456-000, page 46, line 8 to 12.
(g) (f) divided by (a). NPV and Lev. Nom calculated as in (e).
(h) As prescribed by Dr. Hieronymus.
(i), (j) EIA's *Annual Energy Outlook* per Dr. Hieronymus except coal from supplemental Table 90, Arizona/New Mexico sub-bituminous coal prices.
(k) As prescribed by Dr. Hieronymus.
(l), (m), (n) Fuel price indexes created from (i), (j), (k).
(o) Total fuel price index created from (l), (m), (n) using weights of 27% of natural gas, 44% for coal, and 29% for nuclear per Mr. Davis' Direct Testimony at page 19, lines 19 to 26.
(p) (h) multiplied by (o).

EXHIBIT CRR-3

Exhibit No. ___ (CRR-3)

EXCERPTS FROM DIRECT TESTIMONY AND EXHIBITS OF EUGENE T. MEEHAN IN DOCKET NO. ER02-456-000

Exhibit No. GEN-2
Application Under FPA 205
of Electric Generation LLC

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Electric Generation LLC	)	Docket No. ER02-___-000

DIRECT TESTIMONY AND EXHIBITS

OF

EUGENE T. MEEHAN

November 30, 2001

011211-0194-1

III. SUMMARY OF FINDINGS

Q. Have you prepared a brief overview of the analyses that you conducted and a summary of your conclusions?

A. Yes, I have.

Q. Please present the overview and summary of conclusions.

A. The PSA is a long-term bulk power contract that was developed during the period beginning in April 2001 through the date of this filing. The PSA provides Reorganized PG&E with the right to dispatch and receive all energy, capacity and ancillary services from an approximately 7,100 megawatt portfolio of nuclear and hydro generation resources and contract entitlements. The PSA is expected to go in to effect on January 1, 2003, and will last for twelve years. During year 12, the amount of capacity, energy and ancillary services will ramp down by about 50%, enabling Reorganized PG&E to arrange for future needs in an orderly fashion. Based on my review of over 100 contracts that were executed in the United States over the last eighteen months, I, have concluded that the PSA is as favorable to Reorganized PG&E (considering both price and non-price terms) as any combination of contracts that could have provided quantities of energy, capacity and ancillary services comparable to the PSA. I reached this conclusion despite a host of conservative assumptions that caused the contracts I used in my analysis to appear less costly (or the PSA to appear to be more costly) than would have been the case with a less conservative — and more realistic — economic analysis. The cost of the PSA in the consists of seven contracts for peaking and four contracts for base load power.[5] Of these eleven contracts, one was signed in February, one in April, three in May, one in June, three in July and three in August. While I did not screen contracts by date signed, the result of the screening methodology I used was to concentrate my analysis on contracts signed after FERC's orders mitigating prices in California and after power market conditions had returned to stable conditions. I concentrated my benchmarking pricing comparison on the Comparison Group, which consists of only the DWR contracts most favorable to the buyer, *i.e.*, the lowest priced. In addition, most of the contracts in the Comparison Group are also dispatchable as opposed to must take. In contrast, many of the contracts I excluded from the Comparison Group are not only more expensive, but also have undesirable non-price features such as must-take provisions. The contracts that remain are the Comparison Group. The prices for contracts in the Comparison Group are as follows:

Contracts	Levelized Price $/MWh
Comparison Group base load	$57
Comparison Group peaking	$79
PSA	$52

I do not mean to imply that all contracts in the Comparison Group are less expensive than the contracts that have been excluded. With respect to base load power, the Clearwood contract at $69.90/MWh and the Coral base load contract at $76.71/MWh

5 The baseload and peaking components of the Sempra and Coral contracts are considered separately, *i.e.*, treated as separate contracts.

weighted average price of these contracts is $100 per MWh, including ancillary services costs. Individually, each of these contracts is more expensive than the PSA. I have given no weight to these contracts as their terms are too short to enable them to provide comparable service. These contracts are not in the focus group as they are not comparable in terms of the relevant product.

- Second, I have identified transactions that offer steep discounts to the forward market in 2001 and 2002. Some of these extend to 2010 and beyond. They generally have a single fixed price from 2001 to the termination point. There are approximately 3,000 MW of these contracts and the average price is $84 per MWh, including ancillary services costs. Again, each of these contracts is substantially more expensive than the PSA. To be conservative, I have given very little weight to these contracts, because the contract prices during the comparable period to the PSA may have been increased to offset the early period discount. In other words, these contracts prices may be "back loaded." The sellers have offered low initial prices, but have likely compensated for the early year discounts by increasing rates in the later years of the contract. I excluded these contracts because the rates in the comparable post-2003 period may have been skewed upwards given the back loading of the contracts. For example, the Allegheny Energy contract offers blocks of around-the clock and peak power from 2001 through 2011, with MW quantities ranging from 150 MWs to 1000 MWs. This is must-take power priced at a flat $61/MWh for the entire period. As of March 22, 2001 (the date the Allegheny Energy contract was signed), the forward market for blocks of peak power at NP-15 for the balance of the year (April to December) was $278/MWh. Exhibit No. GEN-4 lists and describes the contracts that offer near-term discounts. These contracts are in the focus group, but do not qualify for the Comparison Group.

- The third category is wind power. I gave virtually no weight to these contracts because each is more expensive than the PSA, and wind power cannot be used to replicate the generation profile associated with the PSA. The average price of the wind contracts is $59 per MWh, or $62/MWh with ancillary services. Exhibit No. GEN-5 lists and describes these contracts. These contracts are not in the focus group as the delivery pattern cannot be relied on to replicate the PSA.

- The fourth category consists of fixed price contracts from gas units that were signed prior to May and do not fall into the other categories. There are three contracts in this category: High Desert, Williams and Calpine's February 26, 2001 contract. I do not directly include these contracts in my comparison. However, these contracts do validate the prices of other transactions that are included in my Comparison Group. The High Desert contract, which is priced at $58/MWh, or $61/MWh with ancillary services, is the lowest cost contract in this group. At the time the contract was signed, gas prices were higher than they were during late spring and summer of 2001, and in order to offer a fixed price the seller would have had to lock-in gas supply. However, after adjusting this contract price for the actual drop in gas prices of about $1 per decatherm from the signing date to the present, the contract is priced very similarly with other base load contracts that are indexed to gas. Therefore, while I do not directly consider this contract as a comparison contract, it serves as confirmation of the validity of other contracts that I do weigh heavily. I have reached the same conclusions about the Williams and Calpine contracts, which are priced at $72 per MWh and $64 per MWh respectively, after adjusting for ancillary service costs. These contracts could be viewed as being in the Comparison Group, with prices adjusted downward to reflect the drop in gas prices since early in 2001. Exhibit No. GEN-6 lists and describes these contracts. These contracts are in the focus group, but are not explicitly in the Comparison Group.

I consider the remaining DWR contracts, *i.e.*, those not in the four categories described above, to be comparable to the PSA, and refer to them as the Comparison Group.[9] There are eleven contracts in this Comparison Group which are listed on Exhibit No. GEN-7.[10] Based on these contracts, I conclude that the PSA is at least as favorable to Reorganized PG&E as a contract for a comparable product that could have been negotiated with a non-affiliated seller during the contemporaneous period. Also, it should be noted that each of the contracts not included in the Comparison Group is more expensive than the PSA; therefore, including one or more of those

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9 The Sunrise Power contract does not appear in any of the categories because I was unable to ascertain an exact price for this contract. The heat rate is redacted from the contract. I did perform a test to see whether it would affect the Optimal Portfolio for reasonable expectations of heat rates. This showed that Sunrise was more expensive than the contracts in the Optimal Portfolio and would not affect my price comparison.

10 The baseload and peaking components of two of the contracts — the Sempra and Coral contracts — are considered separately, *i.e.*, treated as separate contracts. As discussed below, this is a conservative approach.

values per MWh of load that have historically been observed in both PJM and the New York ISO.

Q. How does the $1.78/MWh ancillary service cost translate into $2.50/MWh?

A. Taking 2003 as an example, the forecast PG&E native load is about 77,000 GWh. The forecast net generation from the portfolio is about 31,953 GWh. I multiplied $1.78/MWh by the forecast load to determine total PG&E ancillary service cost. I divided that value by the net generation of the portfolio to estimate the ancillary service value assuming that the portfolio provided 100 percent of PG&E's needs. I then multiplied that number by 0.7 to determine the value of the portfolio ancillary services if the portfolio provides 70 percent of PG&E's needs. The result was $3.00/MWh. I then calculated the same value, assuming the portfolio provided 60 percent of PG&E's needs. The result was $2.57/MWh. The value of $2.50/MWh is determined by choosing a round value at the low end of the range.

Many of these ancillary services are from Helms, the pumped storage plant. In the last year of the contract, Helms, which does not phase out, is a larger portion of the portfolio. Hence, the use of a constant $2.50/MWh for ancillary services is conservative as the value would be greater in the last year when Helms is a greater proportion of the portfolio.

Q. You testified that for the second and third analyses (the least cost portfolio dispatch analyses) you constructed an optimal portfolio of contracts to replicate the pattern of generation of the PSA. Please describe that analysis.

A. In order to determine which resources comprise the Optimal Portfolio, I have conducted a "cross-over" analysis of the contracts in the Comparison Group. A crossover analysis is a standard practice in the industry, used to calculate the lowest cost combination of resources to meet a profile of energy use, given the fixed and variable costs of the plants concerned. A cross-over analysis develops the total cost of operating each plant or contract for a given number of hours. The fixed costs are incurred regardless of dispatch. Variable costs are a function of the hours dispatched. A cross-over analysis examines and graphs for a kW of plant capacity the total cost at each number of dispatched hours from zero hours to 8760 hours (the number of hours in the year). Each plant is represented by a line on the graph. The line nearest the horizontal axis identifies the lowest cost plant for the corresponding number of hours. When the lowest line crosses over the next line a new type of contract or plant becomes the lowest cost. The crossover analysis identifies the least cost plants for the number of hours dispatched. Exhibit GEN-12 shows the results of the cross-over analysis. The cross-over results are applied to the generation duration curve (Exhibit GEN-1) to determine the optimal mix. This is done by identifying the amount of capacity on the generation duration curve falling in to each optimal plant type. For example, if a plant type is optimal for all hours in excess of 4000, and 50% of the capacity on the generation duration curve operates in excess of 4000 hours, that plant type would represent 50% of the optimal portfolio.

For this analysis, I used levelized fixed and variable costs. In conducting this analysis, I made some simplifying assumptions that may understate the cost of the portfolio of benchmark contracts. Specifically, for contracts that were must take, but contained a separate $/MWh capacity charge and fuel charge, I assumed that only the capacity charge was must take and that the fuel charge would vary with dispatch. For contracts that contained peaking and base load elements, I assumed that the proportions of peaking and base load could be varied. To the extent that these assumptions are not correct, the cost of the comparison portfolio relative to the PSA would rise.

Q. Please describe your findings from this crossover analysis.

A. Assuming base-case gas prices and the fixed and variable costs shown in Exhibit No. GEN-7, the lowest cost combination to meet the PSA requirement is 3,708 MW of PacifiCorp, signed July 6, 2001, and 612 MW of Sempra Peak, signed February 28, 2001, and 195 MW of Calpeak Midway, signed August 24, 2001, and 2,066 MW of Wellhead Power Gates, signed August 13, 2001. This is illustrated in Exhibits GEN-12 and GEN-13 for the base gas scenario.

This combination of contracts implies PacifiCorp running at an average utilization factor of 91% and for a total of 29,637 GWh, Sempra Peak running at an average utilization factor of 81% and for a total of 2,443 GWh, CalPeak Midway running at an utilization factor of 86% for a total of 416 GWh, and Wellhead Gates running at an average utilization factor of 16% for a total of 1,362 GWhs.[20] The relative energy weightings of the contract, in MWh terms, are therefore 88%, 7%, 1%, and 4% respectively.

Q. How did you apply the mix from the crossover analysis to compute the portfolio cost for the least cost dispatch analysis?

A. I used the MWh weights above applied to the $/MWh cost of each contract at its minimum cost point (*i.e.*, maximum energy availability) as described previously and shown in Exhibit No. GEN-9 to compute the portfolio cost. The weighted average cost of the optimal replacement portfolio using the base case gas price is $56.82/MWh. This compares to the PSA cost of $52.29/MWh.

Q. What interpretation can be placed on the weighted average cost calculated from this analysis?

A. As described above, this is a conservative methodology that assigns only a portion of the capacity costs of each contract to the benchmark comparison. It assumes that for all hours in which the alternate portfolio would have been able to generate more energy than needed to replicate the PSA, the value of such excess generation would equal the pro rata capacity cost and that such excess generation could be sold to the

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20 Utilization has been calculated as a percentage of the maximum number of hours the capacity is contractually eligible to run.

EXHIBIT CRR-4

Exhibit No. ___ (CRR-4)

EXCERPTS FROM PG&E AFFILIATE PPA

Execution Copy

Master Power Purchase & Sale Agreement

EDISON ELECTRIC INSTITUTE

Other Changes

1. Section 1.23 is deleted and the following substituted in its place: "Force Majeure" means any occurrence beyond the reasonable control of a party which causes the party to be unable to perform an obligation under this Agreement in whole or in part and which could not have been avoided by the exercise of due diligence. Force Majeure includes an act of God; actual or threatened civil disturbance, terrorism, war, or riot; strike or other labor dispute; emergencies declared by the California Independent System Operator or any other authorized successor or regional transmission organization or any state or federal regulator or legislature; explosion; tsunami, fire, ice, flood, earthquake, earth movement (including mud slides or rock slides), storm, effect of storm, drought, lightning and other natural catastrophes; regulatory requirements of generic applicability or regulatory requirements not related directly to actions of the Party claiming Force Majeure requiring a shut-down or curtailment of Diablo Canyon; or system transients or voltage reduction requiring a shut-down or curtailment of Diablo Canyon. Force Majeure shall not be based on (i) Buyer's inability economically to use or resell the Product purchased hereunder, or (ii) Seller's ability to sell the Product at a price greater than the Contract Price. Neither Party may raise a claim of Force Majeure based in whole or in part on curtailment by a Transmission Provider unless (i) the Party claiming Force Majeure contracts for firm transmission service with a Transmission Provider for the Product to be delivered to or received at the Delivery Point and (ii) such curtailment is due to "force majeure" or "uncontrollable force" or a similar term as defined under the Transmission Provider's tariff; provided, however, that existence of the foregoing events shall not be sufficient to conclusively or presumptively prove the existence of a Force Majeure absent a showing of other facts and circumstances which in the aggregate with such events establish that a Force Majeure as defined in the first sentence hereof has occurred. Applicability of Force Majeure to the Transaction is governed by the terms of the Products and Related Definitions contained in Schedule P and as set forth in any Confirmations for any Transactions.

2. A new Section 1.62 is added to read: "Good Industry Practice" means any of the practices, methods, and acts engaged in or approved by a significant portion of the electric power industry for the applicable type of electric generation facilities (e.g., conventional hydro, pumped storage, or nuclear,) during the relevant time period, or any of the practices, methods, and acts which, in the exercise of reasonable judgment in the light of the facts known at the time the decision was made, could have been expected to accomplish the desired result at a reasonable cost consistent with good business practices, reliability, safety, and expedition. Good Industry Practice does not require use of the optimum practice, method, or act, but only requires use of practices, methods, or acts generally accepted in the region covered by the Western Systems Coordinating Council or any other successor or similar organization.

3. Section 1.19 is deleted and the following substituted in its place: "Effective Date" means the Effective Date of the Proposed Plan of Reorganization Under Chapter 11 of the Bankruptcy Code for Pacific

Gas and Electric Company, Chapter 11 Case No. 01-30923-DM.

4. The first sentence of Section 2.3 is deleted and the following substituted in its place: Seller may confirm a Transaction by forwarding to Buyer by facsimile or otherwise no later than three (3) Business Days after a Transaction is entered into a confirmation ("Confirmation") substantially in the form of Exhibit A and, to the extent that either party sends the other an invoice for a payment obligation that purports to include any terms and conditions governing a Transaction (other than invoice instructions authorized by Section 6.2 of the Master Agreement), such terms and conditions shall not apply unless they are accepted pursuant to Article Two of this Master Agreement.

5. Section 3.2 is deleted and the following substituted in its place: Seller shall arrange, be responsible for and pay for transmission service to the Delivery Point and shall Schedule or arrange for Scheduling services with its Transmission Providers, as specified by the Parties in the Transaction, or in the absence thereof, in accordance with the practice of the Transmission Providers, to deliver the Product to the Delivery Point. Buyer shall arrange, be responsible for and pay for transmission service at and from the Delivery Point and shall Schedule or arrange for Scheduling services with its Transmission Providers to receive the Product at the Delivery Point.

6. Section 3.3 is deleted and the following substituted in its place: To the extent that either Party is prevented by Force Majeure from carrying out in whole or part, its obligations under the Transaction and such Party (the "Claiming Party") gives notice and details of the Force Majeure to the other Party as soon as practicable, then, unless the terms of the Product specify otherwise, the Claiming Party shall be excused from the performance of the obligations with respect to such Transaction (other than the obligation to make payments then due or becoming due with respect to performance prior to the Force Majeure). The Claiming Party shall use due diligence to remedy the Force Majeure. The non-Claiming Party shall not be required to perform or resume performance of its obligations to the Claiming Party corresponding to the obligations of the Claiming Party excused by Force Majeure.

7. Section 4.1 is deleted and the following substituted in its place: If Seller fails to schedule and/or deliver all or part of the Product pursuant to a Transaction, and such failure is not excused under the terms of the applicable Transaction or by Buyer's failure to perform, then (x) Seller shall pay Buyer, on the date payment would otherwise be due in respect of the month in which the failure occurred or, if "Accelerated Payment of Damages" is specified on the Cover Sheet, within five (5) Business Days of invoice receipt, an amount for such deficiency equal to the positive difference, if any, obtained by subtracting the Contract Price from the Replacement Price; (y) Buyer shall reduce the price it pays to Seller in accordance with the terms and conditions of the Transaction into which Buyer and Seller may enter pursuant to this Master Agreement providing for such adjustment; and/or (z) any other remedy upon which the Parties may

preceding sentence shall only arise if the Option Buyer exercises its Option in accordance with its terms. Seller shall be responsible for any costs or charges imposed on or associated with the Product or its delivery of the Product up to the Delivery Point. Buyer shall be responsible for any costs or charges imposed on or associated with the Product or its receipt at and from the Delivery Point.

3.2 Transmission and Scheduling. Seller shall arrange and be responsible for transmission service to the Delivery Point and shall Schedule or arrange for Scheduling services with its Transmission Providers, as specified by the Parties in the Transaction, or in the absence thereof, in accordance with the practice of the Transmission Providers, to deliver the Product to the Delivery Point. Buyer shall arrange and be responsible for transmission service at and from the Delivery Point and shall Schedule or arrange for Scheduling services with its Transmission Providers to receive the Product at the Delivery Point.

3.3 Force Majeure. To the extent either Party is prevented by Force Majeure from carrying out, in whole or part, its obligations under the Transaction and such Party (the "Claiming Party") gives notice and details of the Force Majeure to the other Party as soon as practicable, then, unless the terms of the Product specify otherwise, the Claiming Party shall be excused from the performance of its obligations with respect to such Transaction (other than the obligation to make payments then due or becoming due with respect to performance prior to the Force Majeure). The Claiming Party shall remedy the Force Majeure with all reasonable dispatch. The non-Claiming Party shall not be required to perform or resume performance of its obligations to the Claiming Party corresponding to the obligations of the Claiming Party excused by Force Majeure.

ARTICLE FOUR: REMEDIES FOR FAILURE TO DELIVER/RECEIVE

4.1 Seller Failure. If Seller fails to schedule and/or deliver all or part of the Product pursuant to a Transaction, and such failure is not excused under the terms of the Product or by Buyer's failure to perform, then Seller shall pay Buyer, on the date payment would otherwise be due in respect of the month in which the failure occurred or, if "Accelerated Payment of Damages" is specified on the Cover Sheet, within five (5) Business Days of invoice receipt, an amount for such deficiency equal to the positive difference, if any, obtained by subtracting the Contract Price from the Replacement Price. The invoice for such amount shall include a written statement explaining in reasonable detail the calculation of such amount.

4.2 Buyer Failure. If Buyer fails to schedule and/or receive all or part of the Product pursuant to a Transaction and such failure is not excused under the terms of the Product or by Seller's failure to perform, then Buyer shall pay Seller, on the date payment would otherwise be due in respect of the month in which the failure occurred or, if "Accelerated Payment of Damages" is specified on the Cover Sheet, within five (5) Business Days of invoice receipt, an amount for such deficiency equal to the positive difference, if any, obtained by subtracting the Sales Price from the Contract Price. The invoice for such amount shall include a written statement explaining in reasonable detail the calculation of such amount.

ARTICLE FIVE: EVENTS OF DEFAULT; REMEDIES

"Transmission Contingent" means, with respect to a Transaction, that the performance of either Seller or Buyer (as specified in the Transaction) shall be excused, and no damages shall be payable including any amounts determined pursuant to Article Four, if the transmission for such Transaction is unavailable or interrupted or curtailed for any reason, at any time, anywhere from the Seller's proposed generating source to the Buyer's proposed ultimate sink, regardless of whether transmission, if any, that such Party is attempting to secure and/or has purchased for the Product is firm or non-firm. If the transmission (whether firm or non-firm) that Seller or Buyer is attempting to secure is from source to sink is unavailable, this contingency excuses performance for the entire Transaction. If the transmission (whether firm or non-firm) that Seller or Buyer has secured from source to sink is interrupted or curtailed for any reason, this contingency excuses performance for the duration of the interruption or curtailment notwithstanding the provisions of the definition of "Force Majeure" in Article 1.23 to the contrary.

"Unit Firm" means, with respect to a Transaction, that the Product subject to the Transaction is intended to be supplied from a generation asset or assets specified in the Transaction. Seller's failure to deliver under a "Unit Firm" Transaction shall be excused: (i) if the specified generation asset(s) are unavailable as a result of a Forced Outage (as defined in the NERC Generating Unit Availability Data System (GADS) Forced Outage reporting guidelines) or (ii) by an event or circumstance that affects the specified generation asset(s) so as to prevent Seller from performing its obligations, which event or circumstance was not anticipated as of the date the Transaction was agreed to, and which is not within the reasonable control of, or the result of the negligence of, the Seller or (iii) by Buyer's failure to perform. In any of such events, Seller shall not be liable to Buyer for any damages, including any amounts determined pursuant to Article Four.

EXHIBIT A

**MASTER POWER PURCHASE AND SALE AGREEMENT
CONFIRMATION LETTER**

This confirmation letter shall confirm the Transaction agreed to on November 30, 2001 between Electric Generation LLC ("Party A") and Pacific Gas and Electric Company ("Party B") regarding the sale/purchase of the Product under the terms and conditions as follows:

Seller: Electric Generation LLC

Buyer: Pacific Gas and Electric Company

Product:

[] Into ________________, Seller's Daily Choice

[] Firm (LD)

[] Firm (No Force Majeure)

[] System Firm

(Specify System: ____)

[X] Unit Firm

(Specify Unit(s)): Capacity and associated Energy, Ancillary Services and any other electrical product that Party B may utilize or sell ("Other Products") (Energy and Ancillary Services hereafter referred to collectively as "Associated Products" and Capacity, Associated Products and Other Products hereafter referred to collectively as "Products") from each of the Units specified in Schedule 1 of this Confirmation. All of the foregoing Units collectively are referred to as the "Portfolio." Each Unit is hereafter referred to as a Unit or Units, a Hydro Unit or Hydro Units or a Diablo Canyon Unit or Diablo Canyon Units, as applicable. The Hydro Units comprise: (1) each of the generating units in the nineteen facilities owned by irrigation districts shown on Schedule 1, which are hereafter referred to as the "I.D. Hydro Units"; (2) each of the generating units in the Hydro Facilities owned directly or indirectly by Gen shown on Schedule 1, which are hereafter referred to as the "Owned Hydro Units"; and (3) the generating unit in the Grizzly Hydro Facility, which is hereafter referred as the "Grizzly Hydro Unit". A "Hydro Facility" is comprised of the powerhouse (including all electrical/mechanical equipment included therein), its directly associated water conveyance system, and its generation tie equipment up to the Interconnection Point. The "Diablo Canyon Facility" means the Diablo Canyon Nuclear Power Plant (including all electrical/mechanical equipment included therein) as described in License Nos. DPR-80 and DPR-82, issued by the Nuclear Regulatory Commission and its generation tie equipment up to the Interconnection Point. Clauses (i) and (ii) of the definition of "Unit Firm" in Schedule P do not apply for this Transaction. Either Party shall be relieved of its obligations to sell and deliver or purchase and receive the Product without liability only to the extent that, and for the period during which, such performance is prevented by Force Majeure and in such case, only to the extent provided for in this Transaction.

[] Other: (______________________________________)

[] Transmission Contingency (If not marked, no transmission contingency)

[]	FT-Contract Path Contingency	[]	Seller	[]	Buyer
[]	FT-Delivery Point Contingency	[]	Seller	[]	Buyer
[]	Transmission Contingent	[]	Seller	[]	Buyer
[X]	Other transmission contingency				

Specify: In accordance with the terms and conditions of this Transaction.

Contract Quantity: The contract quantity respecting the Capacity of each Unit is as set forth in Section 1 of the Confirmation Addendum. Party B is required to accept all Associated Products from the Diablo Canyon Units ("Diablo Canyon Must-Take Quantity") and from the Hydro Units to the extent that hydrological conditions require that such Units operate ("Hydro Units Must-Take Quantity"), subject to Section 4 of the Confirmation Addendum. Except to the extent of accepting the Diablo Canyon Must-Take Quantity and the Hydro Units Must-Take Quantity, Party B shall have the right to dispatch the Units in accordance with the terms and conditions of this Transaction

Delivery Point: The Delivery Point is at the point of interconnection with the transmission or distribution system, as appropriate, for each of the Units as set forth more particularly in the Interconnection Agreements between Party A and Etrans LLC dated as of the Effective Date and between Party A and Party B dated as of the Effective Date. The Delivery of Products from the Tule River Hydro Facility shall be at the fence line of the Tule switchyard.

Contract Price:

(1) Capacity Charge: Peak Season: July and August – $20.50/kW-Month per MW; Shoulder Season: June, September, and October – $15.25/kw-Month per MW; Off-Peak Season: November through May - $12.00/kw-Month per MW, multiplied in each case by the Contract Capacity and as adjusted pursuant to Section 1.3 and 2 of the Confirmation Addendum and the following paragraph (3) of this section on Contract Price;

(2) Energy Charge: For all Units other than Helms Pumped Storage Project No. 2735 ("Helms"), $8/MWh as adjusted by the following paragraph (3) of this section on Contract Price; For Helms, $0.4/MWh as adjusted by the following paragraph (3) of this Section on Contract Price.

(3) Starting on the first day of the Second Contract Year, the Capacity Charge and the Energy Charge shall be escalated based on the percentage change in the then most recently published final Consumer Price Index, All Urban Consumers, All Cities as published by the U.S. Department of Labor, Bureau of Labor Statistics ("CPI-U"), using as a base for determining such escalation the most recently published final CPI-U as of the Effective Date. Thereafter the base for determining escalation shall be the most

recently published final CPI-U as of the first day of the Contract Year immediately preceding the Contract Year for which the escalation is computed.

(4) Notwithstanding Section 9.2 of the Master Agreement, the Capacity Charge shall be increased or decreased to account for the effect of any imposition of a new tax or other assessment or increase in an existing tax or other assessment (but not local real property taxes or other similar taxes) or a tax credit or other reduction in an existing tax or other assessment (but not local real property taxes or other similar taxes) enacted after the date on which this Master Agreement and Confirmation Letter are filed with FERC that is not of general applicability and is instead directed at the generation, sale, purchase, ownership, operation and/or transmission of Capacity, Energy or Ancillary Services, and/or other energy goods and services or ownership or operation of assets related to same.

(5) If Party A deviates from a dispatch instruction of Party B that conforms to the requirements of this Transaction and, as a result, Party B incurs a net loss as a result of an ISO charge, penalty or other similar assessment, Party A shall be responsible for all such charges, penalties or other similar assessments if such deviation from a dispatch instruction was the result of Party A's failure to apply Good Industry Practice. To compute such net loss, Party B shall for each event determine the total amount of gains and losses associated with Party A's deviation from any dispatch instruction of Party B that conforms to the requirements of this Transaction. Such gains include but are not limited to revenues Party B may receive from the ISO as a result of over-generation. If, on an annual basis, the losses for such events exceed the gains, Party B shall submit to Party A an invoice setting forth the amount of any ISO charge, penalty or other similar assessment for which Party A is responsible. Notwithstanding the foregoing: (1) Party B shall take all commercially reasonable steps to mitigate such charges, penalties or other similar assessments following notification by Seller of such deviation or upon Party B's otherwise becoming aware of such deviation and (2) Party A may not without Party B's consent deviate from a prior dispatch instruction of Party B that conforms to the requirements of this Transaction in order to maximize gains to Party B and to thereby reduce its potential liability to Party B under this Section.

(6) To the extent required in any currently effective Reliability Must Run ("RMR") Contracts, on or before the Effective Date, Party A will assign any such RMR contracts to Party B in accordance with their applicable terms and Party B agrees to accept such assignment and to be bound to such RMR contracts. To the extent Party B receives any revenues from any assigned RMR Contract, it shall retain all such revenue, except for Incremental Administrative Costs, Monthly Surcharge Payments, the ISO Repair Share, and Motoring Charges for Ancillary Services Dispatch, as each is defined in the applicable RMR Contracts, all of which shall be remitted to Party A. If, following the Effective Date, Party A enters into any new RMR contracts affecting Units then subject to this Transaction, Party A will assign such RMR contracts to Party B in accordance with their applicable terms and Party B will agree to accept such assignment and to be bound to such RMR contracts. Revenues from such additional RMR contracts shall be treated in accordance with the second sentence of this Paragraph 6. If Party B requests Party A to provide motoring services, the charge to Party B shall be the charge for

Diablo Canyon Unit(s) resulting in the loss of capacity, neither Party shall have any further obligations to the other respecting the Diablo Canyon Unit(s) or the Contract Capacity removed from this Transaction pursuant to the first or second sentence, respectively, of this Special Condition 13.

14. If Party A is required to incur material additional costs in connection with the Diablo Canyon Facility relating to security (including, for example but not by way of limitation, increased staffing or physical modifications to the Diablo Canyon Facility) after the date on which this Master Agreement and Confirmation Letter are filed with FERC, Party A and Party B will agree on a commercially reasonable equitable adjustment to the Capacity Charge respecting the Diablo Canyon Facility. The adjustment shall take into account such factors as the duration of the time and extent to which the Diablo Canyon Facility will remain subject to this Transaction; the remaining useful life of the Diablo Canyon Facility; the useful life of any capital items acquired by Party A, the cost of which is subject to this Special Condition 14; and the then existing obligations of each of the Parties entered into in connection with this Transaction. If, within ninety days from the date on which Party A provides Party B with notice of its decision to invoke this Special Condition 14, the Parties are unable to reach agreement on a commercially reasonable equitable adjustment to the Capacity Charge respecting the Diablo Canyon Facility, Party A may, notwithstanding Section 10.15 of the Master Agreement and Section 6.1 of the Confirmation Addendum, petition FERC pursuant to Section 205 of the Federal Power Act to make a determination of the just and reasonable adjustment to such Capacity Payment in light of the factors set forth above. Notwithstanding Section 6.2 of the Confirmation Addendum, the Parties agree that FERC shall have exclusive jurisdiction over this matter.

15. To the extent that the State of California or any agency thereof imposes additional requirements respecting the decommissioning of Diablo Canyon, the costs of such requirements shall be borne entirely by Party B, and Party B shall reimburse Party A for all such costs and keep Party A neutral from the effects of such new requirements. Both Parties agree to enter into or to cause any of their subsidiaries to enter into such new or amended agreements as are necessary to implement the foregoing arrangement.

16. The Parties acknowledge that the Contract Capacity for each Unit set forth in Section 1 of the Confirmation Addendum is net of station service. If a Unit cannot self-supply station service, Party A may, if permitted by tariff, use remotely provided station service from its other Units. When Party A does so, such amount of Energy as is necessary for remotely provided station service shall be deducted from the total amount of Energy delivered to Party A. If Party A is not permitted by any other applicable tariff or elects not to use remotely provided self-supplied station service, Party A shall purchase such station service from Party B or any third party.

17. Party A agrees to provide Party B with copies of any material regulatory filings made on or after the Effective Date that bear on Party A's performance under Special Conditions 10 through 15 of this Confirmation.

During the Peak Season (July and August):

If Availability is equal to or greater than 95%, the Capacity Charge shall be multiplied by [1 + 1.5 * (Availability - 95%)], or;

If Availability is less than 95%, the Capacity Charge shall be multiplied by [1 - 1.5 * (95% - Availability)].

During the Shoulder Season (June, September, and October):

If Availability is equal to greater than 92%, the Capacity Charge shall be multiplied by [1 + 1.0 * (Availability - 92%)], or;

If Availability is less than 92%, the Capacity Charge shall be multiplied by [1 - 1.0 * (92% - Availability)].

During the Off-Peak Season:

December and January:

If Availability is equal to greater than 91%, the Capacity Charge shall be multiplied by [1 + 1.0 * (Availability - 91%)], or;

If Availability is less than 91%, the Capacity Charge shall be multiplied by [1 - 1.0 * (91% - Availability)];

November and February through May:

If Availability is equal to or greater than 90%, the Capacity Charge shall be multiplied by one; or;

If Availability is less than 90%, the Capacity Charge shall be multiplied by [1 - 1.0 * (90% - Availability)].

<u>Section 3 – Scheduled Outages</u>

Section 3.1 – Diablo Canyon Units. Schedule 3 outlines the general timing of scheduled outages for Diablo Canyon through the Delivery Period. Party A shall provide an update to this schedule to Party B at least annually, but more often if changes occur during a Contract Year affecting that Contract Year or the following Contract Year. These updates shall reflect changes in the start and completion dates of the then current scheduled outages. Party A will not schedule any of these outages between June 15 and September 30. Subject to any applicable regulatory requirements, Party B shall have the right to approve the dates of such outages, which approval shall not be unreasonably withheld. The total number of these scheduled

outage days may not exceed forty-two days for each scheduled outage except as provided for in the following two sentences. Party A may, with one year notice to Party B and for each of the two Units at Diablo Canyon extend the length of a scheduled outage by fifteen twenty-four consecutive hour periods for turbine rotor replacements and fifty-five twenty-four consecutive hour periods for steam generator replacements. However, if a turbine rotor replacement is scheduled for the same outage as a steam generator replacement, the total extension will be just fifty-five twenty-four consecutive hour periods. The periods for scheduled outages identified in the sixth, seventh and eighth sentences of this Section 3.1 are allowance periods for the scheduled outages. Party A shall begin and end the scheduled outages under this Section 3.1 by sending Party B an Availability Notice specifying the date and hour on which such scheduled outage shall begin and an Availability Notice specifying the date and hour on which such Scheduled Outage shall end. Notwithstanding any such Availability Notice, for the purposes of computing the Availability Adjustment, Diablo Canyon shall be deemed to be 100% Available during the full allowance periods permitted by (as appropriate) the sixth, seventh and eighth sentences of this Section 3.1. With respect to all other outages, Party A shall coordinate with Party B during the Off-Peak Season (November through May) and for all other times, Party A shall coordinate and agree with Party A on the schedule for such other outages. Nothing in this Section 3.1 limits the right of Party A to schedule such other outages at any time if required for purposes of Good Industry Practice relating to the condition of the Diablo Canyon Units or if required by any applicable regulatory requirement. All outages within the scope of the previous two sentences shall be reflected in a reduction of the Available Capacity used in computing the Availability Adjustment pursuant to Section 2.2.

Section 3.2 – Hydro Units. Party A shall coordinate with Party B respecting outages of the Owned Hydro Units during the Off-Peak Season (November through May). For all other times, Party A shall coordinate and agree with Party B on the outage schedule for the Owned Hydro Units; provided, however, that Party A may schedule an outage at any time if required for purposes of Good Industry Practice relating to the condition of the Unit or if required by any applicable regulatory requirement. Subject to the next sentence of this Section 3.2, if a Hydro Unit is not Available as a result of an outage, whether scheduled or not, such outage shall be reflected in a reduction of the Available Capacity used in computing the Availability Adjustment pursuant to Section 2.2. If due to hydrological or other external conditions, Party B concludes that an Hydro Unit cannot produce Associated Products for a period of time Party B designates, and Party A elects to perform maintenance or repairs on such Hydro Unit during this period, then such Hydro Unit may be deemed in an Availability Notice delivered by Party A pursuant to Section 2.1 to Party B to be Available to the extent and for the period of time as to which the Parties may agree.

Section 4 – Right of Party B to Back-Down Diablo Canyon Units and Hydro Units

Section 4.1 - Diablo Canyon. From time to time Party B may back-down the Diablo Canyon Units in accordance with back-down procedures that the parties will develop. In the event Party B elects to back-down the Diablo Canyon Units in accordance with this Section 4.1 and the Diablo Canyon back-down procedures, it nevertheless shall pay an Energy Charge as if such back-down had not occurred; provided, however, that no such payment for Energy shall be required if the back-down occurs during implementation of the ISO or its successor over-generation protocol or any successor protocol.

EXHIBIT CRR-5

Exhibit No. ___ (CRR-5)

EXCERPTS FROM PACIFICORP PPA WITH DWR

TEN-YEAR POWER PURCHASE AGREEMENT

made

between

PACIFICORP POWER MARKETING, INC.,

as Seller

and

THE CALIFORNIA DEPARTMENT OF WATER RESOURCES,

as Power Purchaser

EXHIBIT B – Monthly Capacity Charge

Monthly Capacity Charge
$15.00 per kW-month

Notes
The Monthly Capacity Charge above incorporates the following fixed charge for gas transportation, which tariff may be changed from time to time pursuant to Article 5.5 of the Agreement:

Gas Transportation Reservation Charges (US Dollars per Dth):

Pipeline	Tariff	Tariff Effective Date	Rate Schedule	Current Reservation Charge ($/Dth)
TC-AB	Standard Tariff	April 1, 2000	FT-D	$0.1086
TC-BC	Standard Tariff	April 1, 2000	FS-1	$0.0489
PG&E GT NW	First Revised Volume No. 1-A	Jan. 1, 2001	FTS-1 MRRS/CES (as may be replaced by new expansion schedules)	$0.3225
			Total Reservation Charges	**$0.4800**

Example Computation of Gas Transportation Reservation Charges:

Converted to US Dollars at current exchange rate of $0.6450 Canadian dollars per US Dollar

Conversion of Reservation Charges to $/kW-mo for Capacity Charge:

Reservation Charge in $/kw-mo:
= [Total Pipeline Reservation Charges ($/Dth) * (Contract Heat Rate/1000) *24 hours per day * Average number of days per month]/1000

= [$0.480*(7200/1000)*24*(365/12)]/1000] = **$2.523/kW-mo.**

EXHIBIT C – Monthly Fixed O&M Charge

The Monthly Fixed O&M Charge shall initially be $1.750/kW-month.

The Monthly Fixed O&M Charge shall be revised as of July 1 each year commencing with July 1, 2002, by the percentage change in the Consumer Price Index, All Urban Consumers, All Cities, as published by the Bureau of Labor Statistics of the United States Department of Labor (the "CPI Index"). To determine the appropriate revision, the CPI Index for March 1 of each year (or nearest publication thereafter) shall be divided by the CPI Index for March 1, 2001 (or nearest publication thereafter). Such ratio shall then be multiplied by the initial Monthly Fixed O&M Charge, above, and rounded to the nearest $0.001 per kW-month, to determine the Monthly Fixed O&M Charge for the relevant annual period (i.e., July 1 through June 30) period.

> *<u>For example</u>, assuming a CPI Index for March 1, 2001 of 145.0, and a CPI Index for March 1, 2004 of 150.0, the applicable Monthly Fixed O&M Charge for the period July 1, 2004 through June 30, 2005 would be:*
>
> *(150.0/145.0) * $1.750/kW-month = $1.810/kW-month.*

advance written notice, amend Exhibit P from time to time to reflect changes to applicable costs.

6.2.4.6 Itemization of Charges Related to Power Purchaser's Schedule Elections. Seller shall calculate and itemize on Power Purchaser's monthly invoice all charges applicable under this Article 6.2.4.

6.2.5 Limitations due to Operational Flow Orders. Notwithstanding Articles 6.2.1 through 6.2.3, Seller may adjust Power Purchaser's schedule as necessary if required to as result of an operational flow order on the pipelines serving the Facility.

6.3 Seller's Rights to Not Deliver. Consistent with Article 16.5, Seller shall be relieved of its obligations to schedule and deliver Power hereunder due to an event or events of Force Majeure. Seller may additionally reduce deliveries to Power Purchaser as set forth in Articles 6.3.1 and 6.3.2.

6.3.1. Forced Outages and Scheduled Maintenance at the Facility. Seller may, but is not obligated to, declare and curtail deliveries to Power Purchaser for any Forced Outage or Scheduled Maintenance Outage at the Facility, subject to a maximum per Operating Year of twelve percent (12%) of the Mwhs that could otherwise be delivered in such Operating Year assuming a flat schedule at the Contract Delivery Rate (the "Facility Outage and Maintenance Pool"). For example, assuming a Contract Delivery Rate of 100 MW and 8760 hours in the Operating Year, the Facility Outage and Maintenance Pool would be 105,120 Mwh (i.e 12% times 100 MW times 8760 hours).

6.3.1.1. Forced Outages. Seller may curtail Power Purchaser's schedule for Forced Outages at the Facility that affect Seller's output, provided that: (a) such curtailment shall not take effect until the start of the next available scheduling hour; and (b) Power Purchaser shall bear a pro rata share of the resulting reduction of the output Seller receives from the Facility, based on the ratio of its schedule to the total unit contingent schedules from the Facility. Seller shall use commercially reasonable efforts to provide Power Purchaser with notice of the expected duration of a Forced Outage, and shall use commercially reasonable efforts to provide Power Purchaser with updates of such notice as circumstances may change.

6.3.1.2. Scheduled Maintenance. Unless otherwise agreed, Seller shall provide Power Purchaser with at least 30 days non-binding advance notice of the estimated time and duration of a Scheduled Maintenance Outage. If Seller has not provided such timely notice, unless otherwise agreed it shall continue to deliver during scheduled maintenance at the Facility. If Seller does provide such timely notice, it shall update Power Purchaser as better information becomes available and shall provide at least 48 hours notice of the start of a Scheduled Maintenance Outage, as well as 48 hours notice of the estimated completion of such Outage. Seller shall use commercially reasonable efforts, consistent with other commitments from the Facility, to consider maintenance outage schedule adjustment requests made by Power Purchaser.

6.3.1.3. To the extent the Facility Outage and Maintenance Pool is exceeded in any Operating Year, then: (i) for the period ending December 31, 2002, Seller shall pay liquidated damages based upon the positive difference, if any, between the On-Peak COB Market Index or Off-Peak COB Market Index, as applicable, and the Energy Price; and (ii) for the period thereafter, Seller shall provide as liquidated damages a pro-rata refund of the Monthly Capacity Charge and Monthly Fixed O&M Charge. Such pro-rata refund shall be based on the following ratio: (a) the numerator shall be the excess number of Mwhs curtailed in an Operating Year for Forced Outages or Scheduled Maintenance Outages at the Facility (i.e., in excess of the Facility Outage and Maintenance Pool); and (b) the denominator shall be the number of MWhs that could be delivered assuming the Facility had an average availability of 88% in such Operating Year with deliveries on a flat schedule at the Contract Delivery Rate (excluding reductions in deliveries for Force Majeure or pursuant to Article 6.3.2). Such ratio shall be applied to the total dollar amount for such Operating Year of both the Monthly Capacity Charge and the Monthly Fixed O&M Charge to determine Power Purchaser's refund. This Article 6.3.1.3 shall not apply to any willful acts of Seller that causes the Facility Outage and Maintenance Pool to be exceeded in any Operating Year.

6.3.1.4 For the period ending December 31, 2002, for any Month when liquidated damages calculated pursuant to Article 6.3.1.3 occur, they shall be reflected as a credit in a separate line item in the monthly invoice. See Exhibit I as an example. For the period beginning January 1, 2003, for any Operating Year when liquidated damages calculated pursuant to Article 6.3.1.3 occur, they shall be reflected as a credit in a separate line item in the invoice for the last Month of such Operating Year (i.e. July) or in the invoice for the first Month thereafter that such liquidated damages calculation is available. See Exhibit I as an example.

6.3.2. Seller's Right to Not Deliver For Any Other Reason. Notwithstanding Article 6.3.1, Seller may additionally and for any reason reduce deliveries by up to the Contract Delivery Rate for up to 3% of the MWhs that could otherwise be delivered in an Operating Year assuming a flat schedule at the Contract Delivery Rate (the "Supplemental Pool"). For example, assuming a Contract Delivery Rate of 100 MW and 8760 hours in the Operating Year, the Supplemental Pool would be 26,280 Mwh (i.e 3% times 100 MW times 8760 hours). Reductions in delivery pursuant to the Supplemental Pool shall not occur in the June 15th through October 15th period without Power Purchaser's mutual consent. Seller shall provide notice to Power Purchaser by 1500 hours 2 Business Days prior to such reduced deliveries. Such reduction shall apply to a On Peak, Off Peak or flat (24 hour) schedule for the Day, as specified by Seller. See Exhibits I and J for examples. For the period beginning January 1, 2003, the Monthly Capacity Charge and the Monthly Fixed O&M Charge shall be partially reduced for any curtailments pursuant to this Article 6.3.2. Such reduction, if any, shall equal: (i) the number of MWhs so curtailed in such month divided by the total MWhs that could otherwise be delivered in such month had such curtailment not occurred, assuming flat deliveries at the Contract Delivery Rate; times (ii) the sum of the Monthly Capacity Charge and the Monthly Fixed O&M Charge.

6.3.3. Seller shall keep an accounting of the Facility Outage and Maintenance Pool and the Supplemental Pool and provide such accounting to Power Purchaser with each Month's invoice.

6.3.4. Changes to Power schedules associated with this Article 6.3 shall first be applied to any deliveries in excess of Monthly Firm Schedules.

6.4 Scheduling Procedures. Seller shall schedule, or cause to have scheduled, Power from the Facility, or otherwise, to the Point of Delivery, or as otherwise provided in Articles 3.3 or 3.4, for delivery to Power Purchaser under this Agreement consistent with Prudent Utility Practices. The amount of Power to be so scheduled by Seller shall be the amount determined pursuant to Article 6.1 hereof (in the case of deliveries during the First Period) or Article 6.2 hereof (in the case of deliveries during the Second Period), but subject in all cases to reductions made pursuant to Article 6.3 hereof. Power Purchaser shall similarly schedule, or cause to have scheduled, an amount of Power, as determined pursuant to Article 6.1 hereof or Article 6.2 hereof, as applicable, and subject to Article 6.3, from the Point of Delivery, or from alternate points as provided in Articles 3.3 or 3.4, to a legitimate control area or load-serving entity consistent with Prudent Utility Practices. Schedules shall be established by Seller no later than 10 a.m. Pacific Prevailing Time on the immediately preceding Business Day prior to the Day (except as provided in Article 6.3.2) on which Power deliveries are to be made; *provided, however,* that for scheduling of deliveries on weekends and holidays (as defined by the North American Electric Reliability Council and as periodically established by the WSCC Interchange Scheduling Subcommittee), Seller and Power Purchaser shall follow prevailing scheduling procedures within the WSCC with regard to multiple day scheduling. Once schedules are established, changes to schedules shall be made only pursuant to Article 6.2.3, Article 6.3.1.1,

EXHIBIT CRR-6

Exhibit No. ___ (CRR-6)

EXCERPTS FROM SEMPRA PPA WITH DWR

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ENERGY PURCHASE AGREEMENT

This ENERGY PURCHASE AGREEMENT (this "Agreement") is made and entered into as of the date set forth below, by and between the Department of Water Resources, an agency of the State of California, with respect to the Department of Water Resources Electric Power Fund separate and apart from its powers and responsibilities with respect to the State Water Resources Development System ("Department") and Sempra Energy Resources, a California corporation ("SER").

RECITALS

A. Department requires electric energy in connection with its responsibilities, as set forth in California Water Code Section 80000 *et seq.*, with respect to the Department of Water Resources Electric Power Fund (the "Fund"), as established by February 1, 2001, Assembly Bill 1, First Extraordinary Session (the "Act").

B. Department solicited bids for energy pursuant to a Request for Bids ("RFB") published by Department on February 2, 2001.

C. Certain affiliates of SER (the "Project Companies") own and operate, or will own, lease and/or operate, the generating facilities described in Appendix B (the "Projects").

D. On February 28, 2001, SER submitted a revised bid pursuant to the RFB to provide energy to Department with the intention of assigning portions of its rights and obligations under any resulting energy purchase agreement to the Project Companies.

E. On February 28, 2001, Department executed SER's bid made pursuant to the RFB.

F. The RFB provides that "[n]o binding commitment shall arise on the part of CDWR to any Bidder under this Request for Bids until and unless the Parties sign documents of agreement that become effective in accordance with their terms"; and

G. This Agreement is the binding and definitive agreement of the Parties as to the energy sale contemplated by SER's bid, Department's acceptance of that bid and subsequent revisions to SER's bid requested by Department.

NOW, THEREFORE, in consideration of the foregoing, and of other good and valuable consideration, the receipt and sufficiency of which are hereby acknowledged, Department and SER hereto agree as follows:

ARTICLE I
DEFINITIONS AND INTERPRETATION

Section 1.01. Definitions. The following terms have the respective meanings in this Agreement:

"AAA" means the American Arbitration Association.

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"WSCC" means the Western Systems Coordinating Council.

Section 1.02. Rules of Interpretation. Unless otherwise provided herein: (a) words denoting the singular include the plural and vice versa; (b) words denoting a gender include both genders; (c) references to a particular part, clause, section, paragraph, article, party, exhibit, schedule or other attachment shall be a reference to a part, clause, section, paragraph, or article of, or a party, exhibit, schedule or other attachment to the document in which the reference is contained; (d) a reference to any statute, regulation, proclamation, ordinance or law includes all statutes, regulations, proclamations, amendments, ordinances or laws varying, consolidating or replacing the same from time to time, and a reference to a statute includes all regulations, policies, protocols, codes, proclamations and ordinances issued or otherwise applicable under that statute unless, in any such case, otherwise expressly provided in any such statute or in the document in which the reference is contained; (e) a reference to a particular section, paragraph or other part of a particular statute shall be deemed to be a reference to any other section, paragraph or other part substituted therefor from time to time; (f) a definition of or reference to any document, instrument or agreement includes an amendment or supplement to, or restatement, replacement, modification or novation of, any such document, instrument or agreement unless otherwise specified in such definition or in the context in which such reference is used; (g) a reference to any person includes such person's successors and permitted assigns in that designated capacity; (h) any reference to "days" shall mean calendar days unless Business Days are expressly specified; (i) any reference to "dollars" or "$" shall mean United States dollars unless otherwise specified; (j) any reference to time is a reference to the time then prevailing, whether standard or daylight savings time, in the specified time zone; (k) if the date as of which any right, option or election is exercisable, or the date upon which any amount is due and payable, is stated to be on a date or day that is not a Business Day, such right, option or election may be exercised, and such amount shall be deemed due and payable, on the next succeeding Business Day with the same effect as if the same was exercised or made on such date or day (without, in the case of any such payment, the payment or accrual of any interest or other late payment or charge, provided such payment is made on such next succeeding Business Day); (l) words such as "hereunder," "hereto," "hereof" and "herein" and other words of similar import shall, unless the context requires otherwise, refer to the whole of the applicable document and not to any particular article, section, subsection, paragraph or clause thereof; and (m) a reference to "including" means including without limiting the generality of any description preceding such term, and for purposes hereof the rule of *ejusdem generis* shall not be applicable to limit a general statement, followed by or referable to an enumeration of specific matters, to matters similar to those specifically mentioned.

ARTICLE II
PURCHASE AND SALE OF ENERGY

Section 2.01. Purchase and Sale of Energy. Seller shall sell and deliver, or cause to be sold and delivered, and Department shall purchase and receive, or cause to be purchased and received, the Energy at the Delivery Point, and Department shall pay Seller the Purchase Price. Seller may provide the Energy from any Project, Market Source or combination of Projects and/or Market Sources and may deliver Energy at any Delivery Point or combination of Delivery Points. Seller shall be responsible for any costs or charges imposed on or associated with the

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Energy up to the Delivery Point. Department shall be responsible for any costs or charges imposed on or associated with the Energy or its receipt at and from the Delivery Point.

Section 2.02. Determination of the Purchase Price.

(a) Purchase Price for Summer 2001. For Summer 2001, the Purchase Price shall be equal to the Summer 2001 Market Price, as adjusted pursuant to Section 10.07; provided, however, that Department shall be required to pay only one hundred and eighty-nine dollars ($189) per MW-hour, as adjusted pursuant to Section 10.07, for Energy during Summer 2001 unless Department fails to complete the Bond Offering by September 30, 2001 and Seller exercises its right to terminate this Agreement under Section 6.05(i).

(b) Purchase Price for October 1, 2001 through May 31, 2003. The Purchase Price shall be, for the portion of the Term commencing at 12:00 a.m. (Pacific Time) on October 1, 2001 and ending at 11:59 p.m. (Pacific Time) on May 31, 2003, the price of Energy set forth in Appendix C, as adjusted pursuant to Section 10.07.

(c) Purchase Price for June 1, 2003 through September 30, 2011. For the portion of the Term commencing at 12:00 a.m. (Pacific Time) on June 1, 2003, Seller shall calculate the Purchase Price using the Gas Price determined in accordance with Section 2.03 and the formulas set forth below for the 7 x 24 Price and the 6 x 16 Price and making adjustments pursuant to Section 10.07:

7 x 24 Price = (Gas Price x [redacted] MMBtu per MW-hour) + $26 per MW-hour

6 x 16 Price = (Gas Price x [redacted] MMBtu per MW-hour) + $31 per MW-hour

Section 2.03. Natural Gas Supply Arrangements.

(a) At least ninety (90) days prior to the commencement of each Fuel Supply Year, SER shall provide to Department a proposed fuel supply plan (the "Fuel Supply Plan") for such Fuel Supply Year. The Fuel Supply Plan will provide information as to how SER intends to procure Natural Gas and associated Natural Gas transportation, distribution, storage and/or other delivery services such that Department can evaluate the Fuel Supply Plan in order to ascertain the expected cost of Natural Gas needed to generate Energy sold under this Agreement. The Parties may meet at mutually agreeable times prior to and during the Fuel Supply Year to discuss any modifications to the Fuel Supply Plan that Department reasonably requests. SER shall act in accordance with the Fuel Supply Plan. Nothing in this Section 2.03 shall be construed as obligating SER to adopt a Fuel Supply Plan or to agree to any modifications to a Fuel Supply Plan that: (i) SER reasonably believes could interfere with its ability to provide the Energy from any combination of the Projects and/or Market Sources; or (ii) SER believes, in its sole discretion, could potentially expose SER to risks, including credit, market or delivery risks, or liabilities that SER considers unacceptable.

(b) After review of the Fuel Supply Plan and no later than thirty (30) days prior to the commencement of the upcoming Fuel Supply Year, Department may elect, at its sole option, to provide up to [redacted] percent [redacted] of the Contractual Gas Requirement for the upcoming Fuel Supply Year from Department's own Natural Gas purchases and will notify SER of the specific quantity of Natural Gas that Department intends to provide pursuant to an election pursuant to this Section 2.03(b). Department shall deliver such Natural Gas, in amounts and at times coincident with Seller's obligation to deliver Energy to Department hereunder, for SER's account to [redacted] Point. Any election under this Section 2.03(b) will be

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...the price of Energy set forth in Appendix C, as adjusted pursuant to Section 10.07.
(c) Purchase Price for June 1, 2003 through September 30, 2011. For the portion of the Term commencing at 12:00 a.m. (Pacific Time) on June 1, 2003, Seller shall calculate the Purchase Price using the Gas Price determined in accordance with Section 2.03 and the formulas set forth below for the 7 x 24 Price and the 6 x 16 Price and making adjustments pursuant to Section 10.07:

7 x 24 Price = (Gas Price x **7 5** MMBtu per MW-hour) + $26 per MW-hour

6 x 16 Price = (Gas Price x **10.0** MMBtu per MW-hour) + $31 per MW-hour

Section 2.01. Natural Gas Supply Arrangements.

(a) At least ninety (90) days prior to the commencement of each Fuel Supply Year, SER shall provide to Department proposed fuel supply plan (the "Fuel Supply Plan") for such Fuel Supply Year. The Fuel Supply Plan will provide information as to how SER intends to procure Natural Gas and associated Natural Gas transportation, distribution, storage and/or other delivery services such that Department can evaluate the Fuel Supply Plan in order to ascertain the expected cost of Natural Gas needed to generate Energy sold under this Agreement. The Parties may meet at mutually agreeable times prior to and during the Fuel Supply Year to discuss any modifications to the Fuel Supply Plan that Department reasonably requests. SER shall act in accordance with the Fuel Supply Plan. Nothing in this Section 2.03 shall be construed as obligating SER to adopt a Fuel Supply Plan or to agree to any modifications to a Fuel Supply Plan that: (i) SER reasonably believes could interfere with its ability to provide the Energy from any combination of the Projects and/or Market Sources; or (ii) SER believes, in its sole discretion, could potentially expose SER to risks, including credit, market or delivery risks, or liabilities that SER considers unacceptable.

(b) After review of the Fuel Supply Plan and no later than thirty (30) days prior to the commencement of the upcoming Fuel Supply Year, Department may elect at its sole option, to provide up to **eighty** percent **(80%)** of the Contractual Gas

[redacted]

Requirement for the upcoming Fuel Supply Year from Department's own Natural Gas purchases and will notify SER of the specific quantity of Natural Gas that Department intends to provide pursuant to an election pursuant to this Section 2.0302). Department shall deliver such Natural Gas in amounts and at times coincident with Seller's obligation to deliver Energy to Department hereunder, for SER's account to **the Southern California Border** Point. Any election under this Section 2.03(B) will be for a full Fuel Supply Year or as otherwise mutually agreed.

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for a full Fuel Supply Year or as otherwise mutually agreed.

(c) The Gas Price is intended to reflect the cost of Natural Gas procured by SER to generate Energy under this Agreement, and Natural Gas provided by Department pursuant to an election under Section 2.05(b) shall be deemed to be provided to SER at no cost. The Gas Price shall be calculated in accordance with the following formula:

$$\text{Gas Price} = \frac{[(S \times P_S) + (B \times P_B)]}{CGR}$$

WHERE:

S = Amounts of Natural Gas (in MMBtu) purchased by SER pursuant to the Fuel Supply Plan described Section 2.03(a).

P_S = The weighted average price of S (in dollars per MMBtu) for the Billing Period.

B = The portion of the Contractual Gas Requirement (in MMBtu) not purchased pursuant to Sections 2.03(a) by SER or provided by Department pursuant to Section 2.03(b), plus amounts of Natural Gas purchased by SER to replace amounts of Natural Gas that Department fails to deliver and less amounts of Natural Gas delivered by Department equivalent to scheduled Energy deliveries curtailed by SER to Department pursuant to Section 2.04(b)(iii), calculated in accordance with the following formula:

$$B = CGR - D - S$$

WHERE:

D = Amounts of Natural Gas (in MMBtu) provided to SER by Department pursuant to an election under Section 2.03(b).

P_B = [redacted] Price (in dollars per MMBtu) for the Billing Period.

CGR = The Contractual Gas Requirement (in MMBtu), calculated in accordance with the following formula:

CGR = (OPE x [redacted] MMBtu per MW-hour) + (BLE x [redacted] MMBtu per MW-hour)

WHERE:

OPE = MW-hours of 6 x 16 on-peak Energy provided during the Billing Period determined by multiplying the 6 x 16 Capacity applicable during such Billing Period, as indicated in Appendix C, by the number of days, excluding Sundays and NERC Holidays, in the Billing Period by sixteen (16).

BLE = MW-hours of 7 x 24 base load Energy provided during the Billing Period determined by multiplying the 7 x 24 Capacity applicable during such Billing Period, as indicated in Appendix C, by the number of days in such Billing Period by twenty-four (24).

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PB **The Southern California Border Gas** Price (in dollars per MMBtu) for the Billing Period.

CGR The Contractual Gas Requirement (in MMBtu), calculated in accordance with the following formula:

CGR = (OPE x **10.0** MMBtu per MW-hour) + (BLE x **7.5** MMBtu per MW-hour)

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Appendix C

Energy and Purchase Price by Time Period

Period	7 x 24 Capacity (MW)	7 x 24 Price ($/MWh)	6 x 16 Capacity (MW)	6 x 16 Price ($/MWh)
6/1/01-9/30/01	–	–	250	[1]
10/1/01-3/31/02	–	–	–	–
4/1/02-9/30/02	150	$100	300	$160
10/1/02-5/31/03	220	$69	–	–
6/1/03-12/31/03	1,000	[2]	350	[3]
1/1/04-2/29/04	1,200	[2]	700	[3]
3/1/04-5/31/04	800	[2]	400	[3]
6/1/04-2/28/05	1,200	[2]	700	[3]
3/1/05-5/31/05	800	[2]	400	[3]
6/1/05-2/28/06	1,200	[2]	700	[3]
3/1/06-5/31/06	800	[2]	400	[3]
6/1/06-2/28/07	1,200	[2]	700	[3]
3/1/07-5/31/07	800	[2]	400	[3]
6/1/07-12/31/07	1,200	[2]	700	[3]
1/1/08-9/30/11	1,200	[2]	400	[3]

[1] 6 x 16 Price for this period is determined in accordance with Section 2.02(a).

[2] 7 x 24 Price for this period is determined in accordance with Section 2.02(c).

[3] 6 x 16 Price for this period is determined in accordance with Section 2.02(c).